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

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: June 27, 2012

RE: Indiana Gasification LLC / 147-30464-00060

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

Notice of Decision: Approval – Effective Immediately

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

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

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

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

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

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

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

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

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

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

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

Enclosures

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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www.idem.IN.gov

June 27,2012

Mr. Mark Lubbers
Indiana Gasification, LLC
P.O Box 55934
Indianapolis, IN 46205

PSD New Source Construction/Part 70
Operating Permit No.: T 147-30464-00060

Dear Mr. Lubbers:

Indiana Gasification, LLC located at CR 200 N and Base Road, Rockport, Indiana in Spencer County submitted a PSD and Title V Operating Permit application to IDEM, OAQ on April 20, 2011 relating to the proposed facility designed to convert Illinois Basin coal and petroleum coke into pipeline-quality SNG and liquefied CO_2. Pursuant to 326 IAC 2-2 and 326 IAC 2-7 the following emission units are approved for construction at the source:

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

(a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

(b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

(g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, to be permitted in 2012, exhausting through one (1) tip, identified as S-001.

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, to be permitted in 2012, exhausting through one (1) tip, identified as S-002.

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, to be permitted in 2012, with methanol, H_2S, COS, and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, to be permitted in 2012, with NO_x, SO_2, H_2SO_4 emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, exhausting through two (2) stacks, identified as S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected sources.]

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, to be permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

(I) One (1) ZLD-Spray Dryer, to be permitted in 2012, nominally rated at 5.6 MMBtu/hr with PM emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

(K) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.
(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6)

identified as emissions unit FUG-SF6, to be permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA and methanation are identified as emissions units FUG and FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

(N) One (1) ZLD Inert Gas Vent identified as EU-033, to be permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

Insignificant and Trivial Activities

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

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

(c) Four (4) rod mill eductor vent stacks, to be permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(d) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(e) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

(f) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vents, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, to be permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

(g) One (1) slag handling storage pad, to be permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(h) One (1) front-end loader activity on the slag storage pad, to be permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

(i) One (1) fixed roof recycle solid tank, to be permitted in 2012, with a nominal capacity of 14,400 gallons, identified as EU-019.

(j) Five (5) fixed roof slurry run tanks, each, to be permitted in 2012, with a nominal capacity of 47,700 gallons, identified as EU-020A through EU-020E.

(k) Two (2) fixed roof grey water tanks, to be permitted in 2012, each with a nominal capacity of 88,000 gallons, identified as EU-021A and EU-021B.

(l) One (1) fixed roof slurry additive tank, to be permitted in 2012, with a nominal capacity of 28,500 gallons, identified as EU-022.

(m) Five (5) open slag sumps, to be permitted in 2012, each with a nominal capacity of 15,600 gallons, identified as EU-023A through EU-023E.

(n) One (1) pressurized Sour Water Stripper Surge Tank, to be permitted in 2012, with a nominal capacity of 175,000 gallons, identified as EU-026.

(o) Six (6) fixed roof sulfuric acid storage tanks, to be permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

(p) Two (2) fixed roof aqueous ammonia storage tanks, to be permitted in 2012, each with a nominal capacity of 31,000 gallons - identified as EU-028A and EU-028B, with ammonia emissions controlled with two (2) water scrubbers identified as C-028A and C-028B, respectively.

(q) One (1) fixed roof Diesel Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 9,240 gallons, identified as EU-029.

(r) One (1) fixed roof Gasoline Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 1,030 gallons, identified as EU-030.

(s) One (1) fixed roof triethylene glycol storage tank, to be permitted in 2012, with a nominal capacity of less than 10,000 gallons, identified as EU-031.

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.

3. Effective Date of the Permit
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.

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

Sincerely,

Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Attachments:
- Updated Permit
- Technical Support Document
- PTE Calculations
- BACT Analysis
- Attachment A, B, C, D and E
- Air Quality Analysis
- CAM Plan

JB

cc:
- File – Spencer County
- Spencer County Health Department
- U.S. EPA, Region V
- SWRO and SERO
- Air Compliance and Enforcement Branch

IDEM

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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PSD/New Source Construction and Part 70 Operating Permit
OFFICE OF AIR QUALITY

Indiana Gasification, LLC
CR 200 N and Base Road
Rockport, Indiana 47635

(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.: T147-30464-00060	
Issued by: Matt Stuckey,Branch Chief Permits Branch Office of Air Quality	Issuance Date: June 27,2012 Expiration Date: June 27,2017

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D.9. EMISSIONS UNIT OPERATION CONDITIONS

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Effective Date of the Permit

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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(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary natural gas (SNG) and liquefied carbon dioxide (CO2) production plant.

Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
General Source Phone Number:	317-490-5078
SIC Code:	4925, 2819
County Location:	Spencer
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Minor Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

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

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

  (1) One (1) barge unloading to hopper transfer point, permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

  (2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

    (a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

    (b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, permitted in 2012, with four (4) control devices, identified as C-

012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

(g) Two (2) classification towers, identified as EU-012T and EU-012U, permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, permitted in 2012, exhausting through one (1) tip, identified as S-001.

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, permitted in 2012, exhausting through one (1) tip, identified as S-002.

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, permitted in 2012, with HAP, VOC and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stack, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, permitted in 2012, with NOx, emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and particulate, H_2SO_4, and SO_2 emissions controlled by two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, and particulate and H_2SO_4 emissions controlled by a high efficiency mist eliminator, exhausting through two (2) stacks, identified as S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, permitted in 2012, with NOx emissions controlled by ultra-low NOx burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected source.]

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

(I) One (1) ZLD-Spray Dryer, permitted in 2012, nominally rated at 5.6 MMBtu/hr with particulate emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb]

(K) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.

(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6) identified as emissions unit FUG-SF6, permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation are identified as emissions unit FUG and FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

(N) One (1) ZLD Inert Gas Vent identified as EU-033, permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

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

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR

63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

(c) Four (4) rod mill eductor vent stacks, permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(d) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(e) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

(f) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vents, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

(g) One (1) slag handling storage pad, permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(h) One (1) front-end loader activity on the slag storage pad, permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

(i) Six (6) fixed roof sulfuric acid storage tanks, permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

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).

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 Revocation of Permits [326 IAC 2-1.1-9(5)]

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit 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.

B.3 Affidavit of Construction [326 IAC 2-5.1-3(h)] [326 IAC 2-5.1-4]

This document shall also become the approval to operate pursuant to 326 IAC 2-5.1-4 when prior to the start of operation, the following requirements are met:

(a) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), verifying that the emission units were constructed as proposed in the application or the permit. The emission units covered in this permit may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emission units differs from the construction proposed in the application, the source may not begin operation until the permit has been revised pursuant to 326 IAC 2 and an Operation Permit Validation Letter is issued.

(c) The Permittee shall attach the Operation Permit Validation Letter received from the Office of Air Quality (OAQ) to this permit.

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

(a) This permit, T147-30464-00060, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

B.5 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.6 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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

B.7 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.8 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.9 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

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

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

B.10 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

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

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

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

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

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

B.11 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

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

B.12 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

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

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

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

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

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

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

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

The Permittee shall implement the PMPs.

(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. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

B.13 Emergency Provisions [326 IAC 2-7-16]

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

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

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

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

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

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Southeast 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 and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058**.**

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

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

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

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

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

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

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

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

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

B.14 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

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

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

(b) In addition to the nonapplicability determinations set forth in Section D of this permit, the IDEM, OAQ has made the following determinations regarding this source.

(1) **40 CFR Part 63 Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers at Area Sources:** This source is not subject to 40 CFR Part 63 Subpart JJJJJJ because the final EPA rule does not regulate area source boilers that fire only natural gas fuel – because they do not emit sufficient urban air toxics to require regulation.

(2) **40 CFR Part 63 Subpart VVVVVV—National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources** While this facility is an area source of HAPs, This source is not subject to 40 CFR Part 63 Subpart VVVVVV because this rule only regulates facilities that use as feedstocks, generates as byproducts, or produces as products any of the hazardous air pollutants (HAP) listed in Table 1 to this subpart. This facility does not use any of the listed HAPs as a feedstock or generate them as products or byproducts.

(3) **40 CFR 60, Subpart D - Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971:**

(A) This source is not subject to 40 CFR Part 60, Subpart D because Although the auxiliary boilers (EU 005A/B) have a heat input capacity greater than 250 MMBtu/hr, each and are steam-generating units, pursuant to 40 CFR 60.40b(j) the auxiliary boilers are exempt from the requirements of NSPS Subpart D because it is instead subject to the requirements of NSPS Subpart Db.

(B) This source is not subject to 40 CFR Part 60, Subpart D because the thermal oxidizers (EUs 007A, B) and the gasifier pre-heat burners (EUs 008A-E) have a maximum design heat input capacity less than 73 MW (250 MMBtu/hr) and they are not steam-generating units.

(4) **40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978:**

(A) This source is not subject to 40 CFR Part 60, Subpart Da because the auxiliary boilers, which can supply steam to an electric generating steam turbine are steam-generating units, but they are not considered an electric utility unit because they will not supply more than 1/3 of its potential electrical output capacity to any utility power distribution system.

(B) This source is not subject to 40 CFR Part 60, Subpart Da because the thermal oxidizers (EUs 007A, B) or gasifier pre-heat burners (EUs 008A-E) since they do not meet the definition of an electric utility steam generating unit. Specifically, the thermal oxidizers and the pre-heat burners do not generated steam, and thus are not steam generating units.

(5) **40 CFR 60, Subpart Dc Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units:** This source is not subject to 40 CFR Part 60, Subpart Dc because the auxiliary boilers (EU 005A/B) have a heat input capacity greater 100 MMBtu/hr and the thermal oxidizers (EUs 007A, B) and the burners (EUs 008A-E) are not steam generating units.

(6) **40 CFR 60, Subpart H - Standards of Performance for Sulfuric Acid Plants:** This source is not subject to 40 CFR Part 60, Subpart H because the Sulfuric Acid Plant, does not meet the rule's definition of a sulfuric acid production unit.

(7) 40 CFR 60 Subparts VVa, III, NNN, RRR and YYY –Standards of Performance that apply to the Synthetic Organic Chemicals Manufacturing Industry. This facility does not manufacturer any of the SOCMI chemicals listed in 40 CFR 60.489.

(8) 40 CFR 60 Subparts J, GGGa, and QQQ – Standards of Performance that apply to petroleum refineries. This facility does not process petroleum and therefore does not meet the definition of petroleum refinery under these standards.

(9) 40 CFR 60 Subparts KKK and LLL – Standards of Performance that apply to natural gas processing facilities. These rules apply to facilities that extract and process natural gas liquids from field gas. This facility does not meet the definition of a natural gas processing facility under these two rules.

(10) **40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984:** These storage tanks listed below are not subject to 40 CFR Part 60, Subpart Ka because these tanks do not store organic materials and have capacities and maximum true vapor pressure less than 151 cubic meters (m^3) and 3.5 kPa.

EU No.	**Tank ID**	**Tank Capacity (Gal)**	**Max. Vapor Pressure Psia**	**40 CFR 60, Supart Kb**	**Tank Vents to:**
023 A	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 B	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 C	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 D	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 E	Slag Sump	25,284	1.52	No (1)	Atmosphere
027 A	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
027 B	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
027 C	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
027 D	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
027 E	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
027 F	Sulfuric Acid Storage Tank	564,016	<0.5	No (1)	Atmosphere
028 A	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
028 B	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
030	Gasoline Tank	1,175	6.20	No (2)	Atmosphere

Note: (1) Tank does not store VOCs.

(2) This source is not subject to NSPS Subpart Kb because the tank does not meet the capacity criteria.

(11) **Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units:** The source will not be subject to any finalized requirements of the “Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units” proposed by U.S. EPA on April 13, 2012 (77 Fed. Reg. 22392), because no electric generating unit at the facility is a 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.

(12) **326 IAC 24 Clean Air Interstate Rule (CAIR):** The source is not subject to the requirements of 326 IAC 24 or the federal final rule issued on August 8, 2011 limiting the interstate transport of NOx and SO2 (76 Fed. Reg. 48208 et seq). Pursuant to 326 IAC 24-1(b)(1)(B) and the applicability requirements of 76 Fed. Reg. 48208, neither rule applies to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale.

(13) **40 CFR Part 72-78 Acid Rain Program:** This source is not subject to the requirements of 40 CFR Part 72-78 because it does not sell greater than 1/3 its generated electricity.

(c) 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.

(d) 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.

(e) 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.

(f) 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).

(g) 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)]

(h) 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.15 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 T147-30464-00060 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.16 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

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

B.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

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

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

(1) That this permit contains a material mistake.

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

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

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

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

B.18 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

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

Request for renewal shall be submitted to:

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

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

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

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

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

B.19 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

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

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

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

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

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

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

B.20 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

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

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

B.21 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) or (c) without a prior permit revision, if each of the following conditions is met:

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

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

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

(4) The Permittee notifies the:

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

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b) or (c). 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) and (c)(1).

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

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

B.22 Source Modification Requirement [326 IAC 2-7-10.5]

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

B.23 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.24 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

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

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

(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.25 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.26 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 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

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

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

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

C.6 Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]

Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the attached plan in Attachment G. The provisions of 326 IAC 6-5 are not federally enforceable.

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

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

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

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

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

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

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

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

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

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

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

(b) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(c) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

C.12 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

C.13 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

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

no later than 180 days from the date on which this source commences operation.

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

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) 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.14 Risk Management Plan [326 IAC 2-7-5(11)] [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.15 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

(II)

(a) CAM Response to excursions or exceedances.

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the 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. 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). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or 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.

(2) 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, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) CAM recordkeeping requirements.

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

C.16 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

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

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

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

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

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

C.17 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]

In accordance with the compliance schedule specified in 326 IAC 2-6-3(b)(1), starting in 2004 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

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

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

The statement must be submitted to:

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

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

C.18 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following:
  (AA) All calibration and maintenance records.
  (BB) All original strip chart recordings for continuous monitoring instrumentation.
  (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:
  (AA) The date, place, as defined in this permit, and time of sampling or measurements.
  (BB) The dates analyses were performed.
  (CC) The company or entity that performed the analyses.
  (DD) The analytical techniques or methods used.
  (EE) The results of such analyses.
  (FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

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

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(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 (326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) 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(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), 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.19 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2][326 IAC 2-3][40 CFR 64][326 IAC 3-8]

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

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

Indiana Department of Environmental Management

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

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

(d) The first report shall cover the period commencing on the date of issuance of this permit or the date of initial start-up, whichever is later, 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.

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

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

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

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

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

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

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

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

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

C.20 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

(a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

(b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

Emissions Unit Description:

(g) Two (2) classification towers, identified as EU-012T and EU-012U, permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

Emissions Unit Description:

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

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

Construction Conditions

General Construction Conditions

D.1.1 Permit No Defense

This permit 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

D.1.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.1.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.1.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Incoming Solid feedstock material handling and the Process area solid feedstock conveying storage, identified as EU-011A/B and EU-012A-AC shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) operation shall be limited as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) shall be limited through the use of a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

  (3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the barge unloading to hopper transfer point (EU-012A) operation shall be controlled by wet suppression with a control efficiency of 90%.

(c) The PM, PM_{10} and $PM_{2.5}$ emissions from the Railcar Unloading to Rail Hoppers (EU-012G/H) operation shall be limited as follows:
  (1) The PM, PM_{10} and $PM_{2.5}$ emissions from the railcar unloading to rail hoppers shall be controlled by a wet dust extraction system or the use of a baghouse.

  (2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

  (3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(d) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) operation shall be limited as follows:
  (1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) shall be controlled by a wet dust extraction system or the use of a baghouse.

  (2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

  (3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(e) The PM, PM_{10} and $PM_{2.5}$ emissions from the Rail Hoppers Unloading to the Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K) operation shall be limited as follows:

  (1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or the use of a baghouse.

  (2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

  (3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(f) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belt to Radial Stacker (EU-012L-M) operation shall be limited as follows:
  (1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belts to the Radial Stacker shall be controlled by a wet dust extraction system or the use of a baghouse.

  (2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

  (3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(g) The PM, PM_{10} and $PM_{2.5}$ emissions from the Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU-012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V) operation shall be limited as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or the use of a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(h) The PM, PM_{10} and $PM_{2.5}$ emissions from the Radial Stacker to Pile (EU-012N-O) operation shall be limited as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a Telescoping chute with dust collection.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

(i) The PM, PM_{10} and $PM_{2.5}$ emissions from the Storage Piles (EU-012W/X) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

(j) The PM, PM_{10} and $PM_{2.5}$ emissions from the Dozer Activities (EU-012P/Q) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

(k) The PM, PM_{10} and $PM_{2.5}$ emissions from the Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012Z, AB, and AC); and truck hopper unloading to the conveyor Belts (EU-012AA) operation shall be limited as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by an enclosed vent to a wet dust extraction system or the use of a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

D.1.5 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.1.6 PM, PM_{10} and $PM_{2.5}$ Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with Condition D.1.4, the baghouses, fabric filter/telescoping chutes, wet dust extraction systems, and the wet suppression for particulate control shall be in operation and control emissions from the Incoming Solid feedstock material handling and the Process area solid feedstock conveying storage, identified as EU-011A/B and EU-012A-AC at all times that the associated emission unit is in operation.

(b) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

(c) In order to ensure compliance with Condition D.1.4(b), wet suppression using water sprays or water fogging at the barge unloading hopper (EU-012A) shall be used continuously when feedstock is being dropped into the hopper. Additionally, the level of the feedstock in the hopper shall not exceed the height of the sides of the hopper.

Wet suppression is not required when:

- It is raining or snowing at the time of the barge unloading, or
- The ambient air temperature is at or below 32°F.

(d) In order to ensure compliance with Conditions D.1.4(i) and (j), wet suppression using water sprays shall be used daily on active areas of the pile (areas with dozer activity and /or new feedstock being loaded). The non-active areas of the pile will have wet suppression applications weekly.

Wet suppression treatments of feedstock piles may be delayed until the next day whenever:

- It is raining or snowing at the time of the scheduled treatment, or
- The ambient air temperature is at or below 32°F
- The subject area is covered by ice or snow or standing water.

D.1.7 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance status with Condition D.1.4(a), not later than one hundred and eighty (180) days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct stack testing of the emissions from a representative baghouse controlling the process area solid feedstock conveying, storage and feed bins identified as EU-011A/B to determine compliance with the PM, PM_{10}, and $PM_{2.5}$ emissions limitations, utilizing methods as approved by the commissioner. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Conditions D.1.4(c) - (h) and (k), not later than one hundred and eighty (180) days after initial startup of the first gasifier, the Permittee shall conduct stack testing of the emissions from a representative dust extraction system or baghouse or one of each if both are used controlling rail unloading to rail hoppers (EU-

012G/H); Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F); Rail Hoppers Unloading to the Conveyor Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K); Stacker Belts to the Radial Stacker (EU-012L-M); Transfer Systems Consisting of Hoppers and Conveyor Belts Transferring Feedstock from the Piles to Classification Tower (EU-012R-S), Classification Towers (EU-012T-U), and Classification Tower to a Day Bin (EU-012V); Truck/Rail Conveyor Transfer Tower (EU-012Y); the truck stations unloading to a truck hopper (EU-012Z, AB and AC); and truck hopper unloading to the conveyor belts (EU-012AA); and one representative baghouse controlling the Radial Stackers to the Pile (EU-012N-O) to determine compliance with the PM, PM_{10}, and $PM_{2.5}$ emissions limitations, utilizing methods as approved by the commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

D.1.8 Broken or Failed Bag Detection

(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 baghouse 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 process line. 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 baghouses 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.

D.1.9 Wet Dust Extraction System Failure Detection

(a) For a wet dust extraction system 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 wet dust extraction system 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 line. 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).

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

D.1.10 Visible Emissions Notations

(a) Visible emission notations of the Process area solid feedstock conveying storage, and feedbins, identified as EU-011A/B, and Incoming Solid feedstock material handling points EU-012B-O, R-V, and Y-AC stack exhausts 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, at least eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

D.1.11 Parametric Monitoring

(a) In order to demonstrate the compliance status with Condition D.1.4(a), the Permittee shall record the pressure drop across the baghouse used in conjunction with the Process area solid feedstock conveying, storage and feed bins (EU-011A/B) operations at least once per day when this unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(b) In order to demonstrate the compliance status with Condition D.1.4(h), the Permittee shall record the pressure drop across the Telescoping Chute/Fabric filter used in conjunction with the Incoming Solid Feed stock Radial Stackers to the Pile (EU-012N-O) operations at least once per day when these unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(c) In order to demonstrate the compliance status with Conditions D.1.4(c), (d), (e), (f) and (k), the Permittee shall record the flow rate of the scrubbing water used in conjunction with each wet dust extraction system, if one is used, at least once per day when the Incoming Solid Feed stock material handling emission units, identified as EU-012 (B-M, T-V, Y- AC) are in operation. When for any one reading, the water flow rate is below 1.5 gpm, the Permittee shall take reasonable response steps. If a baghouse is used, the Permittee shall record the pressure drop across the baghouse at least once a day when the unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation of this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(d) In order to demonstrate the compliance status with Condition D.1.4(g), the Permittee shall record the flow rate of the scrubbing water used in conjunction with the wet dust extraction system, if one is used, at least once per day when the Incoming Solid Feed stock material handling emission units, identified as EU-012 (R-S) are in operation. When for any one reading, the water flow rate is below 5 gpm, the Permittee shall take reasonable response steps. If a baghouse is used, the Permittee shall record the pressure drop across the baghouse at least once a day when the unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation of this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

The instruments used for determining the pressure or flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months or other time period specified by the manufacturer. The Permittee shall maintain records of the manufacturer specifications, if used.

D.1.12 Ambient Temperature Monitoring

To demonstrate the compliance status with Conditions D.1.6(c) and (d), the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32^{o}F.

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

D.1.13 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.10 - Visible Emission Notation, the Permittee shall maintain a daily record of the visible emission notations from the Process area solid feedstock conveying, storage and feedbins, identified as EU-011A/B and Incoming Solid feedstock material handling points EU-012B-O, R-V, and Y--AC. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Conditions D.1.11(a) and (b) - Parametric Monitoring, the Permittee shall maintain a daily record of the pressure drop across the baghouse controlling the Process area solid feedstock conveying storage, and feedbins and across the fabric filter used in conjunction with the Incoming Solid Feed stock Radial Stackers to the Pile (EU-012N-O) when venting to the atmosphere. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

(c) To document the compliance status with Conditions D.1.11(c) and (d) - Parametric Monitoring, the Permittee shall maintain a daily record of the flow rate of the scrubbing water of each wet dust extractor and a daily record of the pressure drop across each baghouse controlling the Incoming Solid Feed stock enclosed handling, identified as EU-012 (B-M), EU-012 (R-V) and (EU-012Y-AC) when venting to the atmosphere. The Permittee shall include in its daily record when a flow rate of the scrubbing water or the pressure drop reading is not taken and the reason for the lack of a reading, (e.g. the process did not operate that day).

(d) To document the compliance status with Conditions D.1.4(b) - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.1.6(c) - PM, PM_{10} and $PM_{2.5}$ Control, the permittee shall maintain the following daily records:

- The date of each unloading operation.
- A log indicating whether or not water sprays were used and whether or not the level in the hopper ever exceeded the height of the sides of the barge unloading hopper during each unloading.

If a treatment is not required and not performed pursuant to D.1.6(c), records shall be maintained documenting the reason (i.e.: the ambient temperature or precipitation).

(e) To document the compliance status with Conditions D.1.4(i), and (j) - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.1.6(d) - PM, PM_{10} and $PM_{2.5}$ Control, the Permittee shall maintain the following daily records :

- The date and approximate time of each feedstock pile watering treatment.

- If a treatment is not required and not performed pursuant to D.1.6(d), records shall be maintained documenting the reason (i.e.: the ambient temperature, precipitation, or the subject area is covered by ice or snow or standing water.

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

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, permitted in 2012, exhausting through one (1) tip, identified as S-001.

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

Construction Conditions

General Construction Conditions

D.2.1 Permit No Defense

This permit 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

D.2.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.2.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.2.4 PM, PM_{10} and $PM_{2.5}$, CO, SO_2, NOx and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Syngas Hydrocarbon Flare, identified as EU-001 shall be as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce PM, PM_{10} and $PM_{2.5}$ emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:
   a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
   b. Flares shall be operated with a flame present at all times.
   c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare PM/PM_{10} emissions shall not exceed 3.21 lb/hour during startup or shutdown, based on a 3-hour average.

D. The Syngas Hydrocarbon Flare $PM_{2.5}$ emissions shall not exceed 3.01 lb/hour during startup or shutdown, based on a 3-hour average.

(2) The CO emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce CO emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The Permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:
   a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
   b. Flares shall be operated with a flame present at all times.
   c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare CO emissions shall not exceed 172.4 lbs/hour during startup or shutdown based on a 3 hour average.

(3) The SO_2 emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce SO_2 emissions during startups, shutdowns, and other flaring events.

The permittee will use methanol, rather than coal or pet coke, as the feedstock in each gasifier during startup conditions requiring syngas flaring, thereby reducing emissions of sulfur dioxide at the syngas hydrocarbon flare.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented

The SO_2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lbs per 24 hours and shall not exceed 1.92 tons per twelve (12) consecutive month period with compliance determined at the end of each month. The SO_2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3-hour average and shall not exceed 0.05 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(4) The NOx emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce NOx emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. The Syngas Hydrocarbon Flare NOx emissions shall not exceed 43.09 lbs/hour during startup or shutdown based on a 3 hour average.

(5) The GHGs emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce GHG emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

D.2.5 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAP from the syngas hydrocarbon flare identified as EU-001 shall be limited by compliance with the SO_2 emission limit is Condition D.2.4(3) and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

D.2.6 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.2.7 Flare Pilot Flame

In order to ensure compliance with Condition D.2.4, the flare must be operated with a flame present at all times when the Syngas Hydrocarbon Flare is in operation and at least one gasifier is in operation or in startup or shutdown. Only natural gas or SNG shall be used in the pilot for the Syngas Hydrocarbon Flare (EU-001).

D.2.8 Compliance Determination Requirements [326 IAC 2-2-3]

The following equations shall be used for determining compliance status with the emission limits in Condition D.2.4:

a. For PM, PM_{10}, $PM_{2.5}$, and NOx:

$$E = F \times HHV \times EF + PE$$

Where:

E = Pollutant emissions (lb/hour)

F = Flow of flared gases (MMscf/hour)

$HHV_{startup}$ = 124.5 Btu/scf, or other value determined by testing

$HHV_{shutdown}$ = 118.6 Btu/scf, or other value determined by testing

$EF_{PM/PM10}$ = 0.0075 lb/MMBtu

$EF_{PM2.5}$ = 0.0070 lb/MMBtu

EF_{NOx} = 0.010 lb/MMBtu

$PE_{PM/PM10/PM2.5}$ = 0.0020 lb/hr from pilot

PE_{NOx} = 0.053 lb/hr from pilot

b. For CO:

$$E = F \times (1\text{ lb mole}/379.49\text{ scf}) \times (\%CO/100) \times (28.01\text{ lb/lb mole}) \times (1 - (DRE/100)) + PE$$

Where:

E = lb/hr CO

F = Flow of flared gases (scf/hour)

$\%CO_{startup}$ = Percent CO in flared gas during startup = 13.5% or other value determined by testing

$\%CO_{shutdown}$ = Percent CO in flared gas during shutdown = 20.4% or other value determined by testing

DRE = Destruction Removal Efficiency = 99.5%

PE = 0.013 lb/hr CO from pilot flame

c. For SO_2:

E = F x EF + PE

Where:

F = Flow of flared gases (scf/hour)

$EF_{startup} = 0.10 \times 10^{-6}$ lbs/scf

$EF_{shutdown}$ = 0.001264 lbs/scf

PE = 0.0002 lb/hr SO_2 from Pilot

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

D.2.9 Flare Parametric Monitoring

(a) To demonstrate the compliance status with Conditions D.2.4:

(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 the flare visible emissions by Reference Method 22 once per day.

(b) The Permittee shall continuously monitor the flow rate, in CFM, of the total gas flow to the flare, including syngas and natural gas or SNG.

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

D.2.10 Record Keeping Requirements

(a) To document the compliance status with Conditions D.2.4:

(1) The Permittee shall maintain records of the monitoring required by Condition D.2.8(a); and

(2) The Permittee shall maintain records of the daily flare visible emissions checks by Reference Method 22

(b) To document the compliance status with Condition D.2.9(b) and Condition D.2.8 – Compliance Determination Requirements, 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 and natural gas or SNG.

(c) To document the compliance status with Condition D.2.4, the Permittee shall maintain records of the date, time, and total number of minutes for each startup and shutdown flaring event.

(d) To document the compliance status with Conditions D.2.4(1)(A), (2)(A), (3)(A), (4)(A), and (5)(A), the Permittee shall maintain a record of:

i. The feedstock used during each gasifier startup that requires flaring.
ii. The routing of gas whenever a gasifier is depressurized during a planned gasifier shutdown.
iii. The operating rate of each gasifier prior to and during a planned shutdown of a gas treatment train.

In addition, the Permittee shall have available for inspection copies of the procedures used to implement the measures in the FMP and records of training sessions on those procedures. The Permittee shall have a written record of each root cause analysis, the actions recommended from the analysis, and documentation on the implementation of any corrective actions stemming from the root cause analyses under the FMP.

(e) To document the compliance status with the emission limits in Condition D.2.4, the Permittee shall maintain monthly records of the PM, PM_{10}, $PM_{2.5}$, NOx, CO, and SO_2 emissions.

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, permitted in 2012, exhausting through one (1) tip, identified as S-002.

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

Construction Conditions

General Construction Conditions

D.3.1 Permit No Defense

This permit 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

D.3.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.3.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.3.4 PM, PM_{10}, $PM_{2.5}$, CO, SO_2, NOx and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Flare, identified as EU-002 shall be as follows:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(2) The CO emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B Comply with the following flare best practices:
a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(3) The SO_2 emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(4) The NOx emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(5) The GHG emissions from the Acid Gas Flare, identified as (EU-002) shall be:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

D.3.5 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.3.6 Flare Pilot Flame

In order to ensure compliance with Condition D.3.4, the flare must be operated with a flame present at all times when the Acid Gas Flare, identified as EU-002 is in operation and at least one gasifier is in operation or in startup or shutdown. Only natural gas or SNG shall be used in the pilot for the Acid gas Flare (EU-002).

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

D.3.7 Flare Parametric Monitoring

To demonstrate the compliance status with Condition D.3.4:

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 the flare visible emissions by Reference Method 22 once per day.

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

D.3.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.3.4:

(1) The Permittee shall maintain records of the monitoring required by Condition D.3.7; and

(2) The Permittee shall maintain records of the daily flare visible emissions checks by Reference Method 22.

(b) To document the compliance status with Conditions D.3.4(1)(A), (2)(A), (3)(A), (4)(A), and (5)(A), the Permittee shall maintain a record of, and have available for inspection, copies of the procedures used to implement the measures in the FMP and records of training sessions on those procedures. The Permittee shall have a written record of each root cause analysis, the actions recommended from the analysis, and documentation on the implementation of any corrective actions stemming from the root cause analyses under the FMP.

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

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, permitted in 2012, with HAPs, VOC and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

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

Construction Conditions

General Construction Conditions

D.4.1 Permit No Defense

This permit 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

D.4.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.4.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.4.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Removal (AGR) Unit vents, identified as EU-007A/B shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from operation of the AGR Regenerative Thermal Oxidizers (C-007A/B) shall not exceed 0.29 pounds per hour, each and good combustion practices shall be used. Only natural gas or SNG shall be used in the AGR Regenerative Thermal Oxidizers (C-007A/B).

D.4.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Removal (AGR) Unit vents, identified as EU-007A/B shall be as follows:

The CO emissions shall be controlled by the use of regenerative thermal oxidizer (RTO) and the CO emissions shall not exceed 48 pounds per hour for the Acid Gas Removal Unit Vents (EU-007A/B), each, based on a 3-hour average.

D.4.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Removal (AGR) Unit vents, identified as EU-007A/B shall be as follows:

The SO_2 emissions shall be reduced by the use of a Rectisol process and SO_2 emissions shall not exceed 3.17 pounds per hour for each Acid Gas Removal Unit Vent (EU-007A/B), based on a 3-hour average.

D.4.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Removal (AGR) Unit vents, identified as EU-007A/B shall be as follows:

The NOx emissions from the Acid Gas Removal Unit Vents (EU-007A/B) shall be controlled by Low NOx Performance with natural gas injection and the NOx emissions shall not exceed 1.98 pounds per hour from each AGR/RTO unit based on a 3-hour average.

D.4.8 VOC Best Available Control Technology (BACT) [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities, General Reduction Requirements), the Best Available Control Technology (BACT) for the for the Acid Gas Recovery Unit vents (EU-007A/B).shall be as follows:

The VOC emissions from the Acid Gas Recovery Unit vents (EU-007A/B) shall be controlled through the use of a Regenerative Thermal Oxidizer on each vent and the VOC emissions for each vent shall not exceed 1.05 pounds per hour based on a 3-hour average.

D.4.9 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Acid Gas Removal (AGR/RTO) Unit vents, identified as EU-007A/B shall be as follows:

(a) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 4,690,000 tons of CO_2 during the first 12 months of operation.

(b) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 6,430,000 tons of CO_2 during the second 12 months of operation.

(c) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1, 290,000 tons of CO_2 during the third 12 months of operation.

(d) Thereafter, the CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1,290,000 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of each month.

D.4.10 Alternate Emissions Limitation During Gasifier Startup Flaring

During startup flaring of the gasifiers, the NOx emissions from the AGR units (EU-007A/B) shall be limited to 2.97 lbs per hour, combined, from both AGR units (EU-007A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

D.4.11 Hazardous Air Pollutants (HAPs) Minor Limits

(a) The Acid Gas Recovery Units, identified as EU-007A/B, Methanol and Carbonyl Sulfide (COS) emissions shall, each be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The Acid Gas Recovery Units, identified as EU-007A/B, combined Hazardous Air Pollutants (HAPs) emissions shall be limited to less than 17.0 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The methanol emissions from the AGRs shall be calculated by the following equation:

Methanol emissions = Vent Flow x Methanol Emissions Factor

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period)
to be monitored continuously by the Permittee.

Methanol Emissions Factor = Methanol emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs methanol/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. Until the initial compliance stack testing is performed, the engineering estimate of 0.127 lbs methanol emitted/million SCF of vent flow shall be used.

(d) The carbonyl sulfide emissions from the AGRs shall be calculated by the following equation:

Carbonyl Sulfide emissions = Vent Flow x Carbonyl Sulfide Emissions Factor

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period)
to be monitored continuously by the Permittee.

Carbonyl Sulfide Emissions Factor = Pounds of Carbonyl Sulfide emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. COS/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. Until the initial compliance stack testing is performed, the engineering estimate of 0.0062 lbs. carbonyl sulfide emitted/million SCF vent gas shall be used.

(e) Total HAP emissions from the AGRs shall be calculated by the following equations:

When there is no AGR vent flow and RTO is in Standby Mode:

Total HAPs Emissions = RTO Fuel Flow in MMBtu/hr. x HAP Emission Factor of 0.00185 lb HAP/MMBtu

When there is AGR vent flow to the RTO:

Total HAP emissions = Methanol Emissions + Carbonyl Sulfide Emissions + Other HAPs Emissions

Where:

Methanol Emissions = Methanol Emissions as quantified in D.4.11(c)

Carbonyl Sulfide Emissions = Carbonyl Sulfide Emissions as quantified in D.4.11(d)

Other HAPs Emissions are calculated by the following formula:

Other HAPs Emissions (with AGR vent flow) = Vent Flow x (Hexane Emissions Factor + Formaldehyde Emissions Factor + Additional HAPs emissions factor)

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period) to be monitored continuously by the Permittee.

Hexane Emissions factor = Pounds of Hexane emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. hexane/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the engineering estimate of 0.0054 lbs. hexane emitted/million SCF vent gas shall be used.

Formaldehyde Emissions factor = Pounds of Formaldehyde emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. formaldehyde/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the engineering estimate of 0.00023 lbs. formaldehyde emitted/million SCF vent gas shall be used.

Additional HAPS Emissions factor = Pounds of any other HAP besides methanol, carbonyl sulfide, hexane, or formaldehyde emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. HAP/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the engineering estimate of 0.00004 lbs. additional HAPs emitted/million SCF vent gas shall be used.

Compliance with the above limits and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

D.4.12 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.4.13 PM, PM_{10} and $PM_{2.5}$ Calculations [326 IAC 2-2]

(a) In order to ensure compliance with Condition D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, the Permittee shall only use natural gas or SNG in the AGR Regenerative Thermal Oxidizers (C-007A/B).

(b) The following equation shall be used for determining compliance status with Condition D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT:

$E = F_{NG} \times HHV \times EF$

Where:

E = PM, PM_{10} and $PM_{2.5}$ emissions, pounds/hour

F_{NG} = Flow of natural gas or SNG to RTO, MMscf/hour

HHV = higher heating value for the fuel combusted

EF = 0.0075 lb PM, PM_{10} and $PM_{2.5}$ /MMBtu

D.4.14 Nitrogen Oxide Control

(a) In order to ensure compliance with Conditions D.4.7 - NOx PSD BACT and D.4.10 - Alternate Emissions Limitation During Gasifier Startup Flaring, the Low NOx burner and natural gas injection system shall be in operation and control emissions from the RTO at all times that the AGR is venting.

(b) The following equation shall be used for determining compliance status with Condition D.4.10 - Alternate Emissions Limitation During Gasifier Startup Flaring:

$E = F_{ng} * HHV * EF$

Where:

E = Pollutant emissions (lb/hr)

F_{ng} = flow of NG or SNG to RTO (mmscf/hr)

HHV = higher heating value of the fuel combusted, in Btu/scf

EF_{NOx} = 0.05 lb/MMBtu until the initial stack test. Thereafter, use factor (lb/MMBtu) developed from most recent stack test

D.4.15 Sulfur dioxide Control and Calculations

(a) In order to ensure compliance with Condition D.4.6, the Rectisol system shall be in operation and control emissions from the Acid Gas Removal (AGR) Unit vents at all times that the AGR is venting. The sulfur content of the vent stream to one of the RTOs shall be sampled monthly in any month in which there are at least twenty-four (24) hours of venting to one of the RTOs.

(b) The following equation shall be used for determining compliance status with the SO_2 limit for the Acid Gas Removal (AGR) Unit vents (EU-007A/B) in Condition D.4.6:

$E_{SO2} = F_{AGR}$ x (S_{ppm}/1,000,000) x (1 lb mole/379.49scf) x (64.06 lbs SO2/lb mole sulfur) x (DRE/100) + F_{NG} x EF

Where:

E_{SO2} = SO_2 emissions, pounds/hour

F_{AGR} = Vent flow from AGR to RTO, scf/hour

DRE = Destruction Removal Efficiency of sulfur to SO_2 = 98%

F_{NG} = Flow of natural gas or SNG to RTO, MMscf/hour

EF = 0.6 lb SO2/MMscf

S_{ppm} = Molar concentration of all sulfur compounds in the vent stream from the AGR to the RTO in ppm, determined during the most recent monthly sampling event

D.4.16 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.4.9, the following equation shall be used to determine the CO_2 emission limit for the Acid Gas Removal (AGR/RTO) Unit vents (EU-007A/B):

$E_{CO2} = F_{NG}$ x HHV x EF_{CO2} x (ton/2000 lb) + F_{AGR} x (1 lb mole/379.49 scf) * ((%CO2 + ((%CO + %C_{other}) x (DRE/100)))/100) x (44.01 lb CO2/lb mole) x (ton/2000lb)

Where:

E_{CO2} = Total CO_2 emissions, tons/month

F_{NG} = flow of natural gas or SNG to RTO, MMscf/month

HHV = higher heating value for the fuel combusted, in Btu/scf

EF_{CO2} = 116.89 lb CO2/MMBtu

F_{AGR} = Vent flow from AGR to RTO, scf/month

%CO2 = 99% or other value determined by sampling

%CO = 1.0% or other value determined by sampling

$\%C_{other}$ = 0.0209% (allowance for trace CH_4, COS, and CH3OH)

DRE = Destruction Removal Efficiency for CO, CH_3OH, CH_4, COS = 99%

D.4.17 Thermal Oxidizer Operation

In order to ensure compliance with Conditions D.4.5, D.4.8 and D.4.11, the associated thermal oxidizer(s) shall be in operation at all times when the Acid Gas Removal (AGR) Unit vents are in operation.

D.4.18 Water Wash Tower Control

In order to ensure compliance with Conditions D.4.11, if the final design of the AGR unit includes a water wash tower, it shall be in operation at all times when the Acid Gas Removal (AGR) Unit vent are in operation, unless a compliant stack test on the AGR unit vents demonstrates that use of the water wash tower is not required to demonstrate compliance.

D.4.19 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.4.5 – CO PSD BACT, not later than 180 days after initial startup of the second gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct CO emissions stack testing of the emissions from the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct CO emissions stack testing of the emissions from the other of the Acid Gas Removal (AGR) units EU-007A or EU-007B. The testing shall utilize methods as approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.4.7 – NOx PSD BACT, not later than 180 days after initial startup of the second gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct NOx emissions stack testing of the emissions from the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct NOx emissions stack testing of the emissions from the other of the Acid Gas Removal (AGR) units EU-007A or EU-007B. The testing shall utilize methods as approved by the Commissioner. The tests for each AGR for NOx emissions shall be done once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.4.8 – VOC BACT, not later than 180 days after initial startup of the second gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct VOC emissions stack testing of the emissions from the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct VOC emissions stack testing of the emissions from the other of the Acid Gas Removal (AGR) units EU-007A or EU-007B. These tests shall utilize methods as approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.4.11 – Hazardous Air Pollutants Minor Limit, not later than 180 days after initial startup of the second gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct methanol, carbonyl sulfide and other HAPs (as determined by IDEM, using the results of the screening test required by Condition D.4.19(e)) emissions stack testing of the emissions from the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct methanol carbonyl sulfide and other HAPs emissions stack testing of the emissions from the other of the Acid Gas Removal (AGR) units EU-007A or EU-007B. These tests shall utilize methods as approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) Not later than 60 days prior to the emissions stack testing required by Condition D.4.19(d), the Permittee shall conduct a screening test for other HAPs present in the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. These tests shall utilize methods as approved by the Commissioner. This requirement shall also apply to the repeat testing required by Condition D.4.19(d). Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.4.20 Thermal Oxidizer Parametric Monitoring

(a) In order to ensure compliance with Conditions D.4.5, D.4.8 and D.4.11, a continuous monitoring system shall be calibrated, maintained, and operated on each thermal oxidizer for measuring operating temperature. For the purposes of this condition, continuous monitoring means recording the temperature no less often than every 15 minutes when the unit is in operation. The output of this system shall be recorded as a three (3) hour average.

(b) From the date of startup until the initial stack test results are available, the RTO temperature shall be maintained at a three (3)-hour average temperature of 1,600°F at all times that the AGR vent is in operation. On and after the date the stack test results are available, the minimum specified temperature is the three (3)-hour average temperature as observed during the most recent compliant stack test.

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(c) Section C - Response to Excursions or Exceedences contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature average below the three hour average established in the most recent compliance stack test is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.4.21 Water Wash Tower Parametric Monitoring

(a) This condition applies if the final design of the AGR unit includes a water wash tower, unless a compliant stack test on the AGR unit vents demonstrates that use of the water wash tower is not required to demonstrate compliance. In order to ensure compliance with Condition D.4.11, a continuous monitoring system shall be calibrated, maintained, and operated for measuring the wash water flow rate to the tower. For the purpose of this condition, continuous means no less than once per fifteen (15) minutes. The output of this system shall be recorded as a three (3)-hour average. From the date of startup until the initial stack test results are available, the wash water flow rate shall be maintained at the manufacturer’s recommended flow rate at all times the AGR vent is in operation. On and after the date the stack test results are available, the minimum specified wash water flow rate is the three (3)-hour average flow rate as observed during the compliant stack test.

(b) Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A flow rate average below the three hour average established in the most recent compliance stack test is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.4.22 Vent Flow Monitoring

In order to demonstrate the compliance status with Conditions D.4.6 – SO_2 PSD BACT, D.4.9 - GHGs PSD BACT, D.4.11 – HAPs Minor Limit, D.4.15 – Sulfur Dioxide Control, and D.4.16 - Greenhouse Gases (GHGs) Calculations, a continuous monitoring system shall be calibrated, maintained, and operated on AGR vent flow to continuously monitor the vent flow from the AGR to the thermal oxidizers. For the purposes of this condition, continuous monitoring shall mean no less often than once per fifteen (15) minutes. The output from this monitoring system shall be recorded whenever the AGRs are in operation.

D.4.23 Compliance Assurance Monitoring (CAM) [40 CFR 64]

The requirements of 40 CFR Part 64 – Compliance Assurance Monitoring (CAM) apply to the Acid Gas Removal (AGR) Unit for CO emissions. Compliance with the CAM plan attached as Appendix D satisfies 40 CFR 64, Compliance Assurance Monitoring (CAM) for the Acid Gas Removal (AGR) Unit for CO emissions.

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

D.4.24 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, D.4.6 – SO_2 PSD BACT, D.4.9 - GHGs PSD BACT, D.4.13 – PM, PM10, and $PM_{2.5}$ Calculations, D.4.15 – Sulfur Dioxide Control and Calculations, and D.4.16 – Greenhouse Gases (GHGs) Calculations, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the RTOs for the Acid Gas Removal (AGR) Unit vents.

(b) To document the compliance status with Conditions D.4.9 - GHGs PSD BACT, D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, and D.4.6 - SO_2 PSD BACT the Permittee shall maintain monthly records of the CO_2, PM, PM_{10} and $PM_{2.5}$, and SO_2 emissions.

(c) To document the compliance status with Condition D.4.10 – Alternate Emissions Limitation During Gasifier Startup Flaring, the Permittee shall maintain monthly records of the NOx emissions during gasifier startup flaring.

(d) To document the compliance status with condition D.4.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly when the unit is in operation and shall be complete and sufficient to establish compliance with the HAP emission limits established in condition D.4.11.

(1) The monthly records of the methanol, carbonyl sulfide, and total HAPs emissions.

(2) Monthly records of when the RTO is in standby mode.

(3) The water flow rate of the water wash tower (if used).

(4) The results of the most recent stack test, setting the emission factors for methanol, carbonyl sulfide, and total HAPs emissions**.**

(e) In order to document the compliance status with Conditions D.4.6 – SO_2 PSD BACT and D.4.15 – Sulfur Dioxide Control, the Permittee shall maintain monthly records of the sulfur content in the AGR vent stream.

(f) In order to document the compliance status with Condition D.4.22 - Vent Flow Monitoring, the Permittee shall maintain monthly records of the vent flow from the AGRs into the RTOs.

(g) In order to document the compliance status with Condition D.4.10 - Alternate Emissions Limitation During Gasifier Startup Flaring, the Permittee shall maintain records of the amount and type of fuel combusted in the RTOs for the Acid Gas Removal (AGR) Unit vents during each hour during which a startup flaring event occurs.

(h) In order to document the compliance status with Condition D.4.20 - Thermal Oxidizer Parametric Monitoring, the Permittee shall maintain continuous temperature records (on a 3 - hour average basis) for each thermal oxidizer to demonstrate compliance.

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

D.4.25 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.4.9 and D.4.11(a) and (b) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, permitted in 2012, with NOx, emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and particulate, H_2SO_4, and SO_2 emissions controlled by two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, and particulate and H_2SO_4 emissions controlled by a high efficiency mist eliminator, exhausting through two (2) stacks, identified as S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

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

Construction Conditions

General Construction Conditions

D.5.1 Permit No Defense

This permit 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

D.5.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.5.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.5.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

D.5.5 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The H_2SO_4 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the H_2SO_4 emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

D.5.6 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The CO emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall not exceed 18.7 pounds per hour, each based on a 3-hour average.

D.5.7 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The SO_2 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a peroxide scrubber, the SO_2 emissions shall not exceed 0.25 lb/ton acid produced and 8.3 lbs SO_2 per hour, each based on a 24-hour block daily average.

D.5.8 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The NOx emissions shall not exceed 10.2 pounds per hour NOx based on a 24-hour block daily average for each Wet Sulfuric Acid unit and, when acid gases are being fed to the unit, the NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by the use of selective catalytic reduction (SCR).

D.5.9 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

The CO_2 emissions from the Wet Sulfuric Acid Plant operation shall not exceed 474,000 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.5.10 Alternative Emissions Limitation During Gasifier Startup Flaring

During startup flaring of the gasifiers, the NOx emissions from the WSA units (EU-015A/B) shall be limited to 15.26 lbs/hr combined from both WSA units (EU-015A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

D.5.11 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.5.12 Nitrogen Oxide Control

In order to ensure compliance with Condition D.5.8, the selective catalytic reduction (SCR) shall be in operation and control emissions from each Wet Sulfuric Acid (WSA) unit at all times that acid gases are being fed to the unit.

D.5.13 Sulfur dioxide Control

In order to ensure compliance with Condition D.5.7, the peroxide scrubber for SO_2 removal shall be in operation and control emissions from each WSA at all times that the WSA is in operation.

D.5.14 PM, PM_{10}, $PM_{2.5}$ and H_2SO_4 Control

In order to ensure compliance with Conditions D.5.4 and D.5.5, the high Efficiency Mist Eliminator and H_2O_2 scrubber shall be in operation and control emissions from each WSA at all times when the WSA is in operation.

D.5.15 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5][326 IAC-2-2-3]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx, CO_2 and SO_2 emissions.

(b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) 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.

(d) Whenever a NOx, SO_2, or CO_2 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, 40 CFR 75 and 40 CFR 96.

D.5.16 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.5.4 – PM, PM_{10} and $PM_{2.5}$ PSD BACT, not later than 180 days after initial startup of the second gasifier but not later than

365 days after the initial startup of the first gasifier, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the first of the Wet Sulfuric Acid EU-015A or EU-015B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the other of the Wet Sulfuric Acid EU-015A or EU-015B. The tests shall utilize methods approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.5.5 – H_2SO_4 PSD BACT, not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct H_2SO_4 emissions stack testing of the emissions from the first of the Wet Sulfuric Acid EU-015A or EU-015B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct H_2SO_4 emissions stack testing of the emissions from the other of the Wet Sulfuric Acid EU-015A or EU-015B. The tests shall utilize methods approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.5.6 – CO PSD BACT, not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct CO emissions stack testing of the emissions from the first of the Wet Sulfuric Acid (WSA) EU-015A or EU-015B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct CO emissions stack testing of the emissions from the other of the Wet Sulfuric Acid EU-015A or EU-015B. These tests shall utilize methods approved by the Commissioner. These tests for each WSA shall be done once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.5.17 Scrubber Parametric Monitoring

(a) In order to demonstrate the compliance status with Conditions D.5.4 and D.5.5, the Permittee shall monitor and record the pressure drop across the scrubber, at least once per day. When for any one reading, the pressure drop across the scrubber is outside the normal range of 1.0 to 5 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(b) In order to demonstrate the compliance status with Conditions D.5.4 and D.5.5, the Permittee shall monitor the flow rate of the scrubbing liquid daily. When for any one reading, the flow rate is below the normal minimum or a minimum established during the latest stack test, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

(c) The instruments used for determining the pressure and flow rate shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months or other time period specified by the manufacturer. The Permittee shall maintain records of the manufacturer specifications, if used.

D.5.18 Scrubber Failure Detection

(a) For a scrubber 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 scrubber 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 line. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

D.5.19 Compliance Assurance Monitoring (CAM) [40 CFR 64]

The requirements of 40 CFR Part 64 – Compliance Assurance Monitoring (CAM) apply to the Wet Sulfuric Acid (WSA) Plant for NO_x, H_2SO_4 and SO_2 emissions. Compliance with the CAM plan attached as Appendix D satisfies 40 CFR 64, Compliance Assurance Monitoring (CAM) for the Wet Sulfuric Acid (WSA) Plant for NO_x, H_2SO_4 and SO_2 emissions.

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

D.5.20 Record Keeping Requirements

(a) To document the compliance status with Condition D.5.15, the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx, SO_2, or CO_2 continuous emission monitoring system (CEMS) occurs in Condition D.5.15, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document compliance with Condition D.5.17(a), the Permittee shall maintain records of the pressure drop readings of the scrubber once per day. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of reading (e.g. the process did not operate that day).

(d) To document compliance with Condition D.5.17(b), the Permittee shall maintain records of the flow rate of the scrubber. The Permittee shall include in its daily record when a reading is not taken and the reason for the lack of reading (e.g. the process did not operate that day).

(e) Section C - General Record Keeping Requirements, contains the Permittee's obligation with regard to the records required by this condition.

D.5.21 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

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

(b) A quarterly summary of the information to document the compliance status with Condition D.5.9 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected sources.]

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

Construction Conditions

General Construction Conditions

D.6.1 Permit No Defense

This permit 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

D.6.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.6.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.6.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Auxiliary natural gas -fired Boiler, identified as EU-005A and B shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0075 lb per MMBtu and only natural gas or SNG shall be used.

D.6.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Auxiliary natural gas -fired Boiler, identified as EU-005A and B shall be as follows:

The CO emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.036 lb/MMBtu based on a 3 - hour average and good combustion practices shall be used.

D.6.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Auxiliary natural gas -fired Boiler, identified as EU-005A and B shall be as follows:

The SO_2 emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0006 lb/MMBtu and only natural gas or SNG shall be used.

D.6.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Auxiliary natural gas -fired Boiler, identified as EU-005A and B shall be as follows:

The NOx emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0125 lb/MMBtu based on a 24-hour block daily average basis and Ultra Low NOx burners with FGR shall be used.

D.6.8 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Auxiliary natural gas -fired Boiler, identified as EU-005A and B shall be as follows:

The GHGs BACT for the Auxiliary Boilers shall be as follows:

(a) Use of natural gas or SNG; and

(b) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)

(c) Boiler designed for 81% thermal efficiency (HHV).

(d) The total CO_2 emissions from the auxiliary boilers shall not exceed 88,167 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.6.9 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAPs from the natural gas-fired auxiliary boilers identified as EU-005A and EU-005B shall be limited by compliance with Condition D.6.10 - Operational Limit and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

D.6.10 Operational Limit

The total throughput of fuel to the two (2) natural gas-fired auxiliary boilers, identified as EU-005A/B, shall not exceed a total firing rate of 1430 billion Btu per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.6.11 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.6.12 Nitrogen Oxide Control

In order to ensure compliance with Condition D.6.7, the Ultra Low NOx burner with FGR shall be installed and utilized at all times that the auxiliary boilers are in operation.

D.6.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5][326 IAC-2-2-3]

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

(b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) 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.

(d) Whenever a NOx CEMS is down for more than twenty-four (24) hours, the Permittee shall follow the best combustion practice.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, 40 CFR 75 and 40 CFR 96.

D.6.14 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.6.5 – CO PSD BACT, not later than 180 days after initial startup of the first gasifier, the Permittee shall perform CO emissions stack testing of the emissions auxiliary boilers EU-005A and EU-005B utilizing methods approved by the Commissioner. These tests shall be done once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.6.8(c) – PSD GHG BACT, not later than 180 days after initial startup of the first gasifier, the Permittee shall perform thermal efficiency testing of the auxiliary boilers EU-005A and EU-005B utilizing methods approved by the Commissioner. These tests shall be done once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.6.15 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Conditions D.6.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.6.6 - SO_2 PSD BACT, the Permittee shall only use natural gas or SNG in the auxiliary boilers EU-005A and EU-005B.

D.6.16 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.6.8(d), the following equation shall be used to determine the CO_2 emission limit for the Auxiliary Boilers:

$E_{CO2} = F \times HHV \times EF_{CO2} \times (ton/2000\ lb)$

Where:

E_{CO2} = Total CO_2 emissions, tons/month

F = Total amount of natural gas or SNG combusted in the auxiliary boilers, MMscf/month

HHV = higher heating value for the fuel combusted, in Btu/scf

EF_{CO2} = 116.89 lb CO_2/MMBtu

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

D.6.17 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.13, the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs in Condition D.6.13, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) In order to document the compliance status with Conditions D.6.4, D.6.6, D.6.8(a) and (d), D.6.10, and D.6.16, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boilers.

(d) To document the compliance status with Condition D.6.8(d), the Permittee shall maintain the monthly records of the total CO_2 emissions from the auxiliary boilers.

(e) To document the compliance status with Condition D.6.10, the Permittee shall maintain the monthly records of the total firing rate of the auxiliary boilers.

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

D.6.18 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

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

(b) A quarterly summary of the information to document the compliance status with Conditions D.6.8(d) and D.6.10 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

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

Construction Conditions

General Construction Conditions

D.7.1 Permit No Defense

This permit 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

D.7.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.7.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.7.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0007 lb /MMBtu, each and only natural gas or SNG shall be used.

D.7.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.056 lb CO/MMBtu, each and shall use good combustion practices.

D.7.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be not exceed 0.0006 lb SO_2/MMBtu, each and natural gas or SNG shall be used.

D.7.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.10 lb NOx /MMBtu, each and good combustion practices shall be used.

D.7.8 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The GHGs BACT for the Gasifier Preheat Burners shall be as follows:

a. The use of good engineering design; and

b. The use of natural gas or SNG.

c. The CO_2 emissions from the Gasifier Preheater Burners shall not exceed 6,438 tons CO_2 per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.7.9 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.7.10 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Conditions D.7.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, D.7.5 - CO PSD BACT, D.7.6 - SO_2 PSD BACT, D.7.7 - NOx PSD BACT and D.7.8(b) - GHGs PSD BACT, the Permittee shall only use natural gas or SNG in the Gasifier Preheat Burners (EU-008A-E).

D.7.11 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.7.8(c), the following equation shall be used to determine the CO_2 emission limit for the Gasifier Preheat Burners (EU-008A-E):

E_{CO2} = F x HHV x EF_{CO2} x (ton/2000 lb)

Where:

E_{CO2} = Total CO_2 emissions, tons/month

F = Total amount of natural gas or SNG combusted in the Gasifier Preheat Burners, MMscf/month

HHV = higher heating value of the fuel combusted, in Btu/scf

EF_{CO2} = 116.89 lb CO_2/MMBtu

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

D.7.12 Record Keeping Requirement

(a) In order to document the compliance status with Conditions D.7.4, D.7.5, D.7.6, D.7.7, D.7.8 and D.7.11, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the Gasifier Preheat Burners.

(b) To document the compliance status with Condition D.7.8(c), the Permittee shall maintain the monthly records of the CO_2 emissions from the Gasifier Preheat Burners.

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

D.7.13 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.7.8(c) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(I) One (1) ZLD-Spray Dryer, permitted in 2012, nominally rated at 5.6 MMBtu/hr with particulate emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

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

Construction Conditions

General Construction Conditions

D.8.1 Permit No Defense

This permit 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

D.8.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.8.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.8.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ZLD-Spray Dryer, identified as EU-032 shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall be controlled by a fabric filter baghouse and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.005 gr/dscf based on a 3 hour average.

D.8.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ZLD-Spray Dryer, identified as EU-032 shall be as follows:

The CO emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.036 lb/MMBtu and good combustion practices shall be used.

D.8.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ZLD-Spray Dryer, identified as EU-032 shall be as follows:

The SO_2 emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall be limited through the use of natural gas or SNG.

D.8.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ZLD-Spray Dryer, identified as EU-032 shall be as follows:

The NOx emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.035 lb/MMBtu and a Low NOx Burner (LNB) shall be used.

D.8.8 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ZLD-Spray Dryer, identified as EU-032 shall be as follows:

The GHGs BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be as follows:

a. The BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be the use of good engineering design and the use of natural gas or SNG.

b. The CO_2 emissions from the ZLD Spray Dryer shall be not exceed 2,884 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of each month.

D.8.9 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.8.10 Nitrogen Oxide Control

In order to ensure compliance with Condition D.8.7, the low NOx burner shall be installed and utilized at all times that this ZLD-Spray Dryer is in operation.

D.8.11 Compliance Determination Requirements [326 IAC 2-2]

In order to ensure compliance with Conditions D.8.5 – CO PSD BACT, D.8.6 - SO_2 PSD BACT, D.8.7 – NOx PSD BACT and D.8.8(a) - GHGs PSD BACT, the Permittee shall only use natural gas or SNG in the ZLD-Spray Dryer (EU-032).

D.8.12 PM, PM_{10} and $PM_{2.5}$ Control [326 IAC 2-7-6(6)]

(a) in order to ensure compliance with Condition D.8.4, the baghouse for particulate control shall be in operation and control emissions from the ZLD-Spray Dryer at all times that this facility is in operation.

(b) In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed units will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed units will be repaired or replaced. The notification shall also include the status of the applicable compliance monitoring parameters with respect to normal, and the results of any response actions taken up to the time of notification.

D.8.13 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate the compliance status with Condition D.8.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, not later than 180 days after initial startup of the fourth gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct stack testing on the baghouse controlling emissions from the ZLD-Spray Dryer, identified as EU-032 to determine compliance with the PM, PM_{10} and $PM_{2.5}$ emissions limitations, utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.8.14 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.8.8(b), the following equation shall be used to determine the CO_2 emission limit for the ZLD Spray Dryer:

E_{CO2} = F x HHV x EF_{CO2} x (ton/2000 lb)

Where:

E_{CO2} = Total CO_2 emissions, tons/month

F = Total amount of natural gas or SNG combusted in the ZLD Spray Dryer, MMscf/month

HHV = higher heating value of the fuel combusted, in Btu/scf

EF_{CO2} = 116.89 lb CO2/MMBtu

D.8.15 Broken or Failed Bag Detection

(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 baghouse 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 process line. 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 baghouses 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.

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

D.8.16 Visible Emissions Notations

(a) Visible emission notations of the ZLD-Spray Dryer, identified as EU-032 stack exhausts (S-014) 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, at least eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

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

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

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

D.8.17 Parametric Monitoring

In order to demonstrate the compliance status with Condition D.8.4, the Permittee shall record the pressure drop across the baghouse used in conjunction with the ZLD-Spray Dryer operations at least once per day when this unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated at least once every six (6) months.

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

D.8.18 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.8.5, D.8.6 and D.8.7, D.8.8, and D.8.14, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the ZLD-Spray Dryer.

(b) To document the compliance status with Condition D.8.8(b) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the CO_2 emissions from each of ZLD-Spray Dryer.

(c) To document the compliance status with Condition D.8.16 - Visible Emission Notation, the Permittee shall maintain a daily record of visible emission notations from the ZLD-Spray Dryer. 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).

(d) To document the compliance status with Condition D.8.17 - Parametric Monitoring, the Permittee shall maintain a daily record of the pressure drop across the baghouse controlling the ZLD-Spray Dryer when venting to the atmosphere. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

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

D.8.19 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.8.8(b) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

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

Construction Conditions

General Construction Conditions

D.9.1 Permit No Defense

This permit 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

D.9.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.9.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.9.4 PM, PM_{10}, $PM_{2.5}$, NOx, CO, SO_2 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the two (2) emergency diesel generators, identified as EU-009A and EU-009B and three (3) firewater pump diesel engines, identified as EU-010A - C shall be as follows:

(a) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(b) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(c) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(d) SO_2: emissions shall be limited through the use of low-S diesel (less than15 ppm sulfur) and limited hours of non-emergency operation;

(e) Each emergency diesel engine shall not exceed 52 hours per year of non-emergency operation; and

(f) The total CO_2 emissions from the emergency engines (EU-009A/B and EU-010A/B/C) shall not exceed 84 tons CO_2 per twelve (12) consecutive month period from non-emergency operation, with compliance determined at the end of each month.

D.9.5 Operating Restrictions During Gasifier Startup Flaring

During startup flaring of the gasifiers, the Permittee shall not test an emergency engine (EU-009A/B and EU-010A/B/C). This operating restriction shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

Compliance Determination Requirements

D.9.6 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.9.4(f), the following equation shall be used to determine the CO_2 emission limit for the emergency engines (EU-009A/B and EU-010A/B/C):

E_{CO2} (tons/month) = F_D x HHV x EF_{CO2} x (ton/2000 lb)

Where:

E_{CO2} = Total CO_2 emissions, tons/month

F_D = Total amount of diesel fuel used in non-emergency operation of the emergency engines (EU-009A/B and EU-010A/B/C), gallons/month

HHV = 0.138 MMBtu/gal

EF_{CO2} = 163.05 lb CO_2/MMBtu

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

D.9.7 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.9.4(c) and (d), the Permittee shall maintain monthly records of the percent sulfur content of the fuel used in the emergency diesel engines and the firewater pump diesel engines.

(b) To document compliance with Condition D.9.4(e), the Permittee shall maintain monthly records of hours of operation of the emergency diesel engines and the firewater pump diesel engines.

(c) To document the compliance status with Conditions D.9.4(f) and D.9.6, the Permittee shall maintain records of the total amount of fuel used each month in non-emergency operation of the emergency engines (EU-009A/B and EU-010A/B/C) and the total CO_2 emissions from the emergency engines (EU-009A/B and EU-010A/B/C).

(d) To document the compliance status with Condition D.9.5, the Permittee shall maintain a record of the date and period of emergency engine testing, and whether startup flaring of the gasifiers occurred during the testing period.

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

D.9.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.9.4(e) and (f) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(e) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

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

Construction Conditions

General Construction Conditions

D.10.1 Permit No Defense

This permit 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

D.10.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.10.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.10.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the ASU Cooling Tower (EU-016A) and the Main Cooling Tower (EU-016B) shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the ASU Cooling Tower (EU-016A) and the Main Cooling Tower (EU-016B) shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and total dissolved solids shall not exceed 1500 ppm based on a daily average.

Compliance Determination

D.10.5 PM, PM_{10} and $PM_{2.5}$ Control

In order to ensure compliance with Condition D.10.4, the high efficiency drift eliminators for particulate control shall be in operation and control emissions from each cooling tower at all times that the cooling tower is in operation.

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

D.10.6 TDS Monitoring

To demonstrate the compliance status with Conditions D.10.4:

The Permittee shall sample the ASU and main cooling towers for total dissolved solids (TDS) once per week.

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

D.10.7 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.10.4, the Permittee shall maintain weekly records of the total dissolved solids (TDS) sampling from the ASU and Main cooling towers.

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

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) Four (4) rod mill eductor vent stacks, permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(f) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vents, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

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

Construction Conditions

General Construction Conditions

D.11.1 Permit No Defense

This permit 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

D.11.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.11.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.11.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Rod Mill Vent, identified as EU-013 A - D shall be as follows:

(1) The PM and PM_{10} emissions from each Rod Mill Vents shall not exceed 0.025 pounds per hour based on a 3-hour average.

(2) The $PM_{2.5}$ emissions from each Rod Mill Vent shall not exceed 0.0074 pounds per hour based on a 3-hour average.

D.11.5 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Air Separation Unit (ASU), identified as EU-017A-B shall be as follows:

(1) The PM and PM_{10} emissions from each Air Separation Unit (ASU) shall not exceed 0.026 pounds per hour based on a daily average.

(2) The $PM_{2.5}$ emissions from the Air Separation Unit (ASU) shall not exceed 0.009 pounds per hour based on a daily average.

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(K) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.

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

Construction Conditions

General Construction Conditions

D.12.1 Permit No Defense

This permit 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

D.12.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.12.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.12.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Paved Plant Haul Roads (FUG-ROAD) shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the paved road (FUG-ROAD) shall be controlled by;

1. Paving all plant haul roads;
2. Use of wet or chemical suppression;
3. Prompt cleanup of any spilled materials; and

with a control efficiency of 90%.

Compliance Determination Requirements

D.12.5 Compliance Determination Requirements

To demonstrate compliance status with Condition D.12.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT:

(a) Wet Suppression for roadway dust control shall be performed on paved Haul Roads, except when:

- It is raining or snowing at the time of the scheduled treatment,

- The subject portion of the haul road is covered by ice or snow or remains wet from recent precipitation or the previous wet suppression, or

- The road is not being used as a haul road on that day.

If the ambient air temperature is below 32°F at the time of a scheduled wet suppression treatment, the permittee may clean the roadway dust with a vacuum sweeper in lieu of the wet suppression treatment.

(b) Compliance shall be demonstrated for each active haul road using records of haul road usage and control measures. The frequency of required roadway dust control treatments for haul roads with between one (1) and ten (10) truck trips per day shall be at least every other day, unless a treatment is not required for one of the reasons under (a) above. For haul roads with more than 10 trucks per day, the frequency shall be sufficient to achieve 90% control based on the following formula or an equivalent:

Control Efficiency = 96 – (0.263 * (T/C))

Where:

Control Efficiency = percent control efficiency

T = Daily truck trips on roadway (truck trips/calendar day)

C = Number of roadway dust control treatments per calendar day

For the purposes of this formula, if at the time of a scheduled roadway dust control treatment, the treatment is not required for one of the reasons under (a) above, such an event shall be counted as a roadway dust control treatment.

(c) Haul truck speed limits on haul roads shall be posted as 15 miles per hour or less.

Compliance Monitoring Requirements

D.12.6 Ambient Temperature Monitoring

To demonstrate the compliance status with Condition D.12.5, the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32°F.

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

D.12.7 Record Keeping Requirements

To document the compliance status with Conditions D.12.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and Condition D.12.5 – Compliance Determination Requirements, the Permittee shall maintain the following daily records for haul roads:

(1) The number of trucks on the haul road each calendar day.

(2) The date, approximate time, and type of each roadway dust control treatment.

(3) If a treatment is not required and not performed pursuant to D.12.5(a), records shall be maintained documenting the reason (i.e.: the ambient temperature, precipitation, already wet roads, haul road not used, etc.).

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) One (1) slag handling storage pad, permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(h) One (1) front-end loader activity on the slag storage pad, permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

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

Construction Conditions

General Construction Conditions

D.13.1 Permit No Defense

This permit 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

D.13.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.13.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.13.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) shall be controlled by a Wet Suppression or Chemical suppression with 90% control efficiency.

Compliance Determination Requirements

D.13.5 Compliance Determination Requirements

To demonstrate compliance status with Condition D.13.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, wet suppression shall be applied weekly to the entire slag storage pile/pad. Dust control is aided by the fact that the incoming slag is inherently wet. Additional wet suppression should be applied if any visible emissions are observed.

Wet suppression treatments of the slag pile area may be delayed until the next day whenever:

- It is raining or snowing at the time of the scheduled treatment,
- The ambient air temperature is at or below 32°F, or
- There is no material stored and no vehicle traffic at the temporary slag storage area.

Compliance Monitoring Requirements

D.13.6 Ambient Temperature Monitoring

To demonstrate the compliance status with Conditions D.13.5, the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32°F.

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

D.13.7 Record Keeping Requirement

To document the compliance status with Conditions D.13.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.13.5 – Compliance Determination Requirements, the Permittee shall maintain the following weekly records:

(1) The date and approximate time of each feedstock pile watering treatment.

(2) If a treatment is not required and not performed pursuant to D.13.5, records shall be maintained documenting the reason (i.e.: the ambient temperature, precipitation, or there is no material stored and no vehicle traffic at the temporary slag storage area)

SECTION D.14 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6) identified as emissions unit FUG-SF6, permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

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

Construction Conditions

General Construction Conditions

D.14.1 Permit No Defense

This permit 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

D.14.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.14.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.14.4 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Electrical Circuit Breakers (FUG-SF_6) shall be as follows:

The GHGs BACT for the Electrical Circuit Breaker (FUG-SF_6) shall be the use of fully enclosed pressurized SF_6 circuit breakers with leak detection (low pressure alarm).

SECTION D.15 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation are identified as emissions unit FUG & FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

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

Construction Conditions

General Construction Conditions

D.15.1 Permit No Defense

This permit 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

D.15.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.15.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.15.4 CO, H_2SO_4 SO_2 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation, identified as emissions unit FUG & FUG-WSA shall be as follows:

(1) The BACT for fugitive leaks of CO and H_2SO_4 is no-controls.

(2) The BACT for the fugitive leaks of SO_2 in the WSA is the use of a Leak Detection and Repair (LDAR) program.

(3) The BACT for fugitive GHG emissions is the use of a leak detection and repair (LDAR) program for the natural gas and SNG piping and weekly audio/visual inspection of the CO_2 compressors while they are in operation in any week in which there are at least twenty-four (24) hours of operation of the CO_2 compressor to be inspected.

The LDAR program is incorporated into the permit in Section E.6

D.15.5 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAPs from the Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation identified as FUG & FUG-WSA shall be limited by compliance with the LDAR program incorporated in Section E.6 for equipment in methanol service and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

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

D.15.6 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.15.4(3), the Permittee shall maintain weekly records of the hours of operation each CO2 compressor.

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

SECTION D.16 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) Six (6) fixed roof sulfuric acid storage tanks, permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

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

Construction Conditions

General Construction Conditions

D.16.1 Permit No Defense

This permit 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

D.16.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.16.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.16.4 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the fixed roof sulfuric acid storage tanks, identified as EU-027A - EU-027F shall be as follows:

The H_2SO_4 emissions from the Sulfuric Acid tanks shall be limited by the use of a fixed roof tank and submerged fill.

SECTION D.17 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

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

Construction Conditions

General Construction Conditions

D.17.1 Permit No Defense

This permit 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

D.17.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.17.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

Compliance Determination Requirements

D.17.4 Vapor Recovery System

In order to ensure compliance, the vapor recovery system must be operated at all times when the methanol tanks, identified as EU-024 and EU-025 are in operation.

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

D.17.5 Vapor Recovery System Parametric Monitoring

(a) In order to ensure compliance, a continuous monitoring system shall be calibrated, maintained, and operated on each vapor recovery system for measuring the temperature of the coolant. For the purposes of this condition, continuous monitoring means recording the temperature no less often than every 15 minutes. The output of this system shall be recorded as a three (3) hour average.

(b) The temperature of the coolant shall be maintained at or below zero (0) degree Fahrenheit or other temperature if demonstrated by stack test or engineering calculations to provide at least 95% control.

(c) Section C - Response to Excursions or Exceedences contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature average above the above temperature in (b) is not considered a deviation from this permit. Failure to take response steps 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.17.6 Record Keeping Requirements

In order to document the compliance status with Condition D.17.5, the Permittee shall maintain continuous temperature records (on a 3 - hour average basis) for each vapor recovery system to demonstrate compliance.

SECTION D.18 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(N) One (1) ZLD Inert Gas Vent identified as EU-033, permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

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

Construction Conditions

General Construction Conditions

D.18.1 Permit No Defense

This permit 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

D.18.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.18.3 Modification to Construction Conditions [326 IAC 2]

All requirements of these construction conditions shall remain in effect unless modified in a manner consistent with procedures established for revisions pursuant to 326 IAC 2.

Operating Conditions

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

D.18.4 Hazardous Air Pollutants (HAPs) Control

The Permittee shall operate a carbon adsorber on the ZLD Inert Gas Vent. The carbon adsorber shall be used at all times the ZLD inert gas vent is in operation except during carbon adsorber maintenance, repair or carbon replacement. The system shall be designed with a carbon replacement interval of no less than once per year (based on maximum design flow rate and mercury concentration).

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

D.18.5 Parametric Monitoring

In order to demonstrate the compliance status with Condition D.18.4, the Permittee shall record the pressure drop across the Sulfided Carbon Adsorbent used on the ZLD Inert Gas Vent at least once per week when this unit is in operation. When the pressure drop exceeds the manufacturer’s recommended maximum pressure drop, the Permittee shall take appropriate action as soon as practicable and not later than during the next scheduled outage of the ZLD system. Actions may include replacement of the carbon, maintenance or repair. A pressure reading that exceeds the manufacturer's recommended maximum pressure drop is not a deviation from this permit. Failure to take response steps pursuant to this condition 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.18.6 Record Keeping Requirement

To document the compliance status with Condition D.18.5 - Parametric Monitoring, the Permittee shall maintain a weekly record of the pressure drop across the Sulfided Carbon Adsorbent controlling the ZLD Inert Gas Vent when venting to the atmosphere. The Permittee shall include in its weekly record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected source.]

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

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart Db]

E.1.1 General Provisions Relating to NSPS Db [326 IAC 12][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the boilers described in this section except when otherwise specified in 40 CFR Part 60, Subpart Db.

E.1.2 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [326 IAC 12][40 CFR Part 60, Subpart Db]

The Permittee who operates a steam generating unit that will commence 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 MMBtu/hr) shall comply with the following provisions of 40 CFR Part 60, Subpart Db, included as Attachment C of this permit. The source is subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b(a);
(2) 40 CFR 60.40b(j);
(3) 40 CFR 60.41b(b);
(4) 40 CFR 60.42b(k)(2);
(5) 40 CFR 60.44b(h);
(6) 40 CFR 60.44b(i);
(7) 40 CFR 60.44b(l);
(8) 40 CFR 60.46b(a);
(9) 40 CFR 60.46b(c);
(10) 40 CFR 60.46b(e)(1);
(11) 40 CFR 60.46b(e)(3);
(12) 40 CFR 60.48b(b);
(13) 40 CFR 60.48b(c);
(14) 40 CFR 60.48b(d);
(15) 40 CFR 60.48b(e)(2);
(16) 40 CFR 60.48b(e)(3);
(17) 40 CFR 60.48b(f);
(18) 40 CFR 60.49b(a);
(19) 40 CFR 60.49b(b);
(20) 40 CFR 60.49b(d);
(21) 40 CFR 60.49b(g);

(22) 40 CFR 60.49b(i); and
(23) 40 CFR 60.49b(o).

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb]

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb]

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

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart Kb]

E.2.1 General Provisions Relating to NSPS Subpart Kb [326 IAC 12-1] [40 CFR 60, Subpart A]

Pursuant to 40 CFR Part 60, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the two storage tanks, identified as Methanol De-Inventory Tank and Fresh Methanol Storage Tank, except when otherwise specified in 40 CFR Part 60, Subpart Kb (*Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*).

E.2.2 Standard of Performance for Volatile Organic Liquid Storage Vessels (NSPS) [40 CFR 60, Subpart Kb] [326 IAC 12]

The Permittee, which operates the volatile organic liquid storage vessels designated as Methanol De-Inventory Tank and Fresh Methanol Storage Tank shall comply with the following provisions of 40 CFR Part 60, Subpart Kb (included as Attachment D of this permit), which are incorporated by reference as 326 IAC 12:

(1) 40 CFR 60.110b(a);
(2) 40 CFR 60.110b(e);
(3) 40 CFR 60.111b;
(4) 40 CFR 60.112b(a)(3);
(5) 40 CFR 60.112b(a)(4);
(6) 40 CFR 60.113b(c);
(7) 40 CFR 60.114b(c);
(8) 40 CFR 60.115b(c);
(9) 40 CFR 60.116b(a);
(10) 40 CFR 60.116b(b);
(11) 40 CFR 60.116b(e); and
(12) 40 CFR 60.116b(g).

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

(a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

(b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

(c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

(d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

(e) One (1) rail conveyor belt to the stacker, identified as EU-012K, permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

(f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

(g) Two (2) classification towers, identified as EU-012T and EU-012U, permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

(h) One (1) classification tower to a day bin, identified as EU-012V, permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

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

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart Y]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for the emission units identified as EU-012 A-AC and EU-011A-B, except as otherwise specified in 40 CFR Part 60, Subpart Y.

E.3.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements [40 CFR Part 60, Subpart Y] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Y, the Permittee shall comply with the provisions of New Source Performance Standards for Coal Preparation and Processing Plants, which are incorporated by reference as 326 IAC 12, (included as Attachment B of this permit), for the above emission units as specified as follows:

(1) 40 CFR 60.250(a);
(2) 40 CFR 60.250(d);
(3) 40 CFR 60.251;
(4) 40 CFR 60.254(b);
(4) 40 CFR 60.254(c);
(5) 40 CFR 60.255(b);
(6) 40 CFR 60.255(c);
(7) 40 CFR 60.255(d);
(8) 40 CFR 60.255(e);
(9) 40 CFR 60.255(f);
(10) 40 CFR 60.255(g);
(11) 40 CFR 60.255(h);
(12) 40 CFR 60.256(b)(1);
(13) 40 CFR 60.256(b)(3);
(14) 40 CFR 60.256(c);
(15) 40 CFR 60.257(a);
(16) 40 CFR 60.258(a)(1);
(17) 40 CFR 60.258(a)(2);
(18) 40 CFR 60.258(a)(3;
(19) 40 CFR 60.258(a)(4);
(20) 40 CFR 60.258(a)(5);
(21) 40 CFR 60.258(a)(6);
(22) 40 CFR 60.258(a)(7);
(23) 40 CFR 60.258(a)(8);
(24) 40 CFR 60.258(a)(10);
(25) 40 CFR 60.258(b)(2);
(26) 40 CFR 60.258(b)(3);

(27) 40 CFR 60.258(c); and
(28) 40 CFR 60.258(d).

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

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

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart IIII]

E.4.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the emergency diesel generators and the firewater pump diesel engines described in this section except when otherwise specified in 40 CFR Part 60, Subpart IIII.

E.4.2 Standards of Performance for Stationary Compression Ingnition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee who owns and operates stationary compression ignition (CI) internal combustion engines (ICE) shall comply with the following provisions of 40 CFR Part 60, Subpart IIII, included as Attachment E of this permit. The source is subject to the following portions of Subpart IIII:

(1) 40 CFR 60.4200(a);
(2) 40 CFR 60.4205(b);
(3) 40 CFR 60.4205(c);
(4) 40 CFR 60.4206;
(5) 40 CFR 60.4207(a);
(6) 40 CFR 60.4207(b);
(7) 40 CFR 60.4208(a);
(8) 40 CFR 60.4208(b);
(9) 40 CFR 60.4208(g);
(10) 40 CFR 60.4209(a);
(11) 40 CFR 60.4211(a);
(12) 40 CFR 60.4211(c);
(13) 40 CFR 60.4211(e);
(14) 40 CFR 60.4212(a);
(15) 40 CFR 60.4212(b);
(16) 40 CFR 60.4212(c);

(17) 40 CFR 60.4214(b);
(18) 40 CFR 60.4218;
(19) 40 CFR 60.4219;
(20) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines;
(21) Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines;
(22) Table 6 to Subpart IIII of Part 60 - Optional 3-Mode Test Cycle for Stationary Fire Pump Engines; and
(23) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart III.

SECTION E.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

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

National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63 Subpart ZZZZ]

E.5.1 National Emissisions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-82-1][40 CFR 63, Subpart ZZZZ]

The Permittee owns and operates stationary reciprocating internal combustion engines (RICE) located at an area source of HAP emissions shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ, included as Attachment A of this permit. The source is subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6590(c)(1);

SECTION E.6 LEAK DETECTION AND REPAIR (LDAR) CONDITIONS FOR THE FUGITIVE EQUIPMENTS LEAKS

Emissions Unit Description:

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA and methanation are identified as emissions unit FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

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

LDAR as BACT, Following National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63 Subpart H]

E.6.1 CO, H2SO4, SO2, and GHG PSD BACT [326 IAC 2-2-3] and Hazardous Air Pollutants (HAPs) Minor Limits

The source is not a major source of HAPs and is not subject to any of the MACT standards under 40 CFR Part 63. However, in the context of the BACT determination for this source and the limitation of HAP emissions, the requirements of 40 CFR 63 Subpart H, addressing equipment leaks, that are listed below, apply to the pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, and control devices or systems that are in service at the facility for the following process streams: methanol streams, propylene streams, and product SNG streams. The same Subpart H requirements apply to any leaks of SO2 in the Wet Sulfuric Acid unit piping between the combustor and oxidation reactor, beginning with the connector at the combustor and ending with the connector at the oxidation reactor, except that references in the regulations to methane or VOCs will instead be applied to the pollutant SO2. These requirements apply to the above listed streams irrespective of the HAP content of the specified streams.

1. 40 CFR 63.161;
2. 40 CFR 63.162(a);
3. 40 CFR 63.162(c);
4. 40 CFR 63.162(d);
5. 40 CFR 63.162(f);
6. 40 CFR 63.162(g);
7. 40 CFR 63.162(h);
8. 40 CFR 63.163;
9. 40 CFR 63.164;
10. 40 CFR 63.165;
11. 40 CFR 63.166
12. 40 CFR 63.167;
13. 40 CFR 63.168;
14. 40 CFR 63.169;
15. 40 CFR 63.170;
16. 40 CFR 63.171;
17. 40 CFR 63.172;
18. 40 CFR 63.173; and
19. 40 CFR 63.174.

The alternative quality improvement program for valves under 40 CFR 63.175 and pumps under 40 CFR 63.176 may be used in lieu of the specified requirements of 40 CFR 63.168 and 40 CFR 63.163. The source may apply any alternative method approved by the EPA Administrator under 40 CFR 63.177(e) with written notification to IDEM 30 days in advance of the use of the alternative method. That notification shall include a copy of the EPA approval of the alternative method and an indication of where at the plant the alternative will be applied.

The test methods and procedures used shall be those delineated under 40 CFR 63.180. For the SO2 monitoring of the components in the Wet Sulfuric Acid (WSA), references to methane or VOCs in 40 CFR 63.180 or 40 CFR 60 Appendix A, Method 21 shall be applied instead to the pollutant SO2. If a monitor is used that has a range lower than the defined leak rate, then any reading within 90% of the monitor’s range shall be treated as a leak.

For Greenhouse Gases BACT any leakage determined by audio/visual or other inspection shall be repaired within the time frames specified in 40 CFR 63.164 (g) except as provided by 63.171. Recordkeeping shall conform to the provisions of 40 CFR 63.181.

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

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Phone:

Date:

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

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Indiana Gasification, LLC
Source Address: CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.: T147-30464-00060

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

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

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

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

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

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

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

Form Completed by:______________________________

Title / Position: _________________________________

Date:____

Phone: ____

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Syngas Hydrocarbon Flare
Parameter:	SO_2 emission during Shutdown event
Limit:	not exceed 1.92 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

Submitted by: ____________________________________
Title / Position: ____________________________________
Signature:____
Date: ____
Phone: ____

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Syngas Hydrocarbon Flare
Parameter:	SO_2 emission during Startup event
Limit:	not exceed 0.05 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: Indiana Gasification, LLC
Source Address: CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.: T147-30464-00060
Facility: Wet Sulfuric Acid Plant
Parameter: CO_2 Emissions
Limit: shall not exceed 474,000 tons per twelve (12) consecutive month period with compliance determine at the end of each month

QUARTER :

YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Auxiliary Boilers
Parameter:	Natural Gas Throughput
Limit:	Shall not exceed 1,430 billion Btu per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :   YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Gasifier Pre-heater Burners
Parameter:	CO_2 Emissions
Limit:	shall not exceed 6,438 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	ZLD Sprayer Dryer
Parameter:	CO_2 Emissions
Limit:	shall not exceed 2,884 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Emergency Diesel Engines (Use one form for each engine)
Parameter:	Number of Hours
Limit:	for each engine shall not exceed 52 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER :   YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Emergency Diesel Engines
Parameter:	CO_2 Emissions
Limit:	shall not exceed 84 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Auxiliary Boilers
Parameter:	CO_2 Emissions
Limit:	shall not exceed 88,164 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	CO_2 Emissions
Limit:	shall not exceed 4,960,000 tons during the first 12 months of operation.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous Months of this 12-month period	To-date Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	CO_2 Emissions
Limit:	shall not exceed 6,430,000 tons during the second 12 months of operation.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous months of this 12- Month period	To-date Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	CO_2 Emissions
Limit:	shall not exceed 1,290,000 tons during the third 12 months of operation.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous months of the 12-Month period	To-date Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: Indiana Gasification, LLC
Source Address: CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.: T147-30464-00060
Facility: Acid Gas Removal Unit Vents (EU-007A/B)
Parameter: CO_2 Emissions
Limit: shall not exceed 1,290,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous months of the 12-Month period	To-date Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	Single HAPs Emissions (Methanol)
Limit:	less than 9 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	Single HAPs Emissions (Carbonyl Sulfide)
Limit:	less than 9 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name:	Indiana Gasification, LLC
Source Address:	CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.:	T147-30464-00060
Facility:	Acid Gas Removal Unit Vents (EU-007A/B)
Parameter:	Total HAPs Emissions
Limit:	less than 17 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Source Name: Indiana Gasification, LLC
Source Address: CR 200 N and Base Road, Rockport, Indiana 47635
Part 70 Permit No.: T147-30464-00060

Months: __________ to ___________ Year: _____________

Page 1 of 2

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

Page 2 of 2

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: ______________________________

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

Indiana Gasification, LLC
CR 200 N and Base Road
Rockport, Indiana 47635

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ______________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ________________________ for ________________________.
(Title) (Company Name)

3. By virtue of my position with __________________________________, I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____.
(Company Name)

4. I hereby certify that Indiana Gasification, LLC CR 200 N and Base Road, Rockport, Indiana 47635, completed construction of the natural gas (SNG) and liquefied carbon dioxide (CO2) production plant on _____________________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on ***April 20, 2011*** and as permitted pursuant to New Source Construction Permit and Part 70 Operating Permit No. T147-30464-00060, Plant ID No. 147-00060 issued on __________.

5. **Permittee, please cross out the following statement if it does not apply:** Additional (operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature_______________________________________
Date____

STATE OF INDIANA)
)SS

COUNTY OF ____________________)

Subscribed and sworn to me, a notary public in and for ______________________ County and State of Indiana on this ___________________ day of _________________, 20 _____. My Commission expires: _______________.

Signature________________________
Name_____________________ (typed or printed)

Indiana Gasification, LLC Analysis of Lead Emissions

Lead Emissions: Lead is present in trace amounts in the coal and petroleum coke that are fed to the IG gasifiers. Coal, coke, and the natural gas that is used as fuel are the only potential sources of air emissions of lead at the IG facility. Although both coal and coke have very low levels of lead content, coal has the greater lead content. Therefore, in this assessment of emissions, the analysis assumes operation on 100% coal.

The highest lead concentration in Indiana coal reported by the Indiana Geological Survey was 167 ppm by weight on a dry basis. This concentration equates to 145 pounds of lead per hour entering the IG gasifier, based on 433 tons per hour of dry coal feed.

When coal is combusted at a power plant, much of the lead is contained in the fly ash and bottom ash but some is emitted in the particulate emissions of the power plant. At the IG facility the coal is gasified rather than combusted and particulate emissions containing lead do not occur. Instead, the lead and certain other metals are substantially removed during the separation of solids from the raw gas and the purification of the gas for conversion to substitute natural gas (SNG). Approximately 33% of the lead ends up in the slag removed from the bottom of the gasifier and is managed as a by-product and shipped off site. Whatever small amount of lead that remains is contained in the syngas. As a result of the temperature and pressure of the quenched syngas, the lead is almost all present as a solid. This solid lead is then removed through the following sequence of processing the syngas to SNG:

1) Syngas water scrubbing
2) Filtering in the shift catalyst bed (about 70% of raw syngas)
3) Filtering in the sulfide carbon bed, that is used to remove mercury
4) Syngas water scrubbing in Rectisol ammonia absorber
5) Syngas methanol scrubbing in Rectisol main absorber
6) Filtering in Guard Bed which is upstream of the Methanation Reactors
7) Filtering in the Methanation Reactor catalyst beds that are in series

The particulate matter, including the lead, removed by these steps ends up in spent catalyst, spend sulfided carbon, spent sulfur guard adsorbent, and spent filter media which will be managed as waste and shipped off-site.

A very small concentration of lead remains as vapor in the SNG, 2.90E-06 lb lead per million BTU HHV. The lead content of natural gas is 4.90E-07 lb lead per million BTU HHV natural gas according to EPA's AP-42 factor for natural gas combustion. Accordingly, as presented in the lead and mercury spreadsheets, attached, the maximum emissions of lead from the use of SNG and natural gas at the site are about 6.6 lbs/year.

The other source of lead emissions is the lead present in particulate emissions from the coal handling, conveying and mill operation. As presented in the attached spreadsheet, the maximum emissions of lead in the coal dust are estimated to be an additional 5.7 lbs/year for a plant wide total of 12.3 lbs/year of lead emissions.

PSD Non-Applicability for Lead Emissions: The PSD significant emissions rate for lead emissions is 0.6 tons/yr. Because the Indiana Gasification facility total lead emissions are well below this level, the PSD regulations require no further analysis for lead emissions.

Indiana Gasification, LLC Analysis of Mercury Emissions

Mercury is present in trace amounts in the coal and the petroleum coke that are fed to the gasifiers. The coal and coke used as feedstocks and natural gas fuel are the sole sources of mercury that has the potential to be emitted to the air. While both coal and coke have very low levels of mercury; of the two, coal has the greater mercury content. Therefore, in this assessment of emissions, the analysis assumes operation on 100% coal.

The highest mercury concentration reported by the Indiana Geological Survey for Indiana coal is 0.86 ppm by weight on a dry basis. This is equivalent to 0.745 pounds of mercury per hour entering the gasifier, based on 433 tons per hour of dry coal feed.

When coal is combusted at a power plant, much of the mercury is vaporized. Some is chemically bound in ash and the rest is emitted. At the IG facility, the coal is gasified rather than combusted and those emissions do not occur. Instead, most of the mercury remains as a vapor in the syngas. That mercury is substantially removed during the purification of the syngas for conversion to substitute natural gas (SNG). This is done by passing the syngas through sulfided carbon beds where the mercury is captured. The sulfided carbon beds are periodically replaced and the spent beds are shipped off site for disposal.

A very small amount of the mercury may be present in the product SNG. As a conservative estimate of what remains, we have used the vendor guaranteed performance of the sulfide carbon guard beds. This translates to a SNG emission factor for mercury of 1.65 lb/10^{12} Btu HHV. This is the factor used to determine maximum emissions of mercury when product SNG is used at the site. On occasions, purchased natural gas is also used. The mercury content of natural gas is estimated at 0.26 lb/10^{12} Btu HHV. As presented in the lead and mercury spreadsheets, attached, the maximum emissions of mercury from the use of SNG and natural gas at the site are estimated to be 3.74 lbs/year.

Some of the mercury also ends up in the quench water which is sent to the Zero Liquid Discharge (ZLD) system. The mercury in the wastewater is then released in the evaporization and crystalization system into an inert gas stream which is also treated with a sulfided carbon adsorption bed. This sulfided carbon bed is also periodically replaced and the spent sorbent is shipped off site for proper disposal. The inert gas vent on the ZLD system is at a very low flow and due to the treatment with the sulfided carbon filter; it represents only 0.72 lbs/year of mercury emissions.

The remaining source of mercury emissions is the mercury present in particulate emissions from the coal handling, conveying and milling operations. As presented in the attached spreadsheet, the maximum emissions of mercury in the coal dust are another 0.03 lbs/year for a plant wide total of 4.6 lbs/year of mercury emissions.

Appendix G: Fugitive Coal and Particulate Matter Dust Emissions Control Plan

Indiana Gasification, LLC
CR 200 North and Base Road
Rockport, Indiana 47635

Introduction

This Fugitive Coal Dust Emissions Control Plan meets the requirements of 40 CFR 60, Subpart Y – Standards for coal processing and conveying equipment, coal storage system, transfer and loading systems, and open storage piles. This plan addresses fugitive coal dust emissions from:

- Barge unloading to hopper, nominally rated at 750 tons per hour, identified as EU-012A;
- Dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q; and
- Incoming feedstock storage piles, with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X.

Additionally, this plan meets the requirements of 326-IAC-6-5 - Fugitive Particulate Matter Emissions Limitations as it applies to the above listed sources as well as the following non-coal fugitive dust emission sources:

- Paved Plant Haul Roads (FUG-ROAD);
- Slag Handling Storage Pad, nominally rated at 43 tons per hour, identified as EU-034A; and
- Front-end Loader on the Slag Storage Pad, nominally rated at 1,440 tons per day, identified as EU-034C.

Other material handling and conveyance operations at the site will be enclosed and routed to control equipment. As such, they are not sources of fugitive particulate emissions and are not addressed in this plan.

Two maps showing fugitive dust sources at the facility are attached. Although the conveyors and transfer points are enclosed and routed to control equipment and therefore are not fugitive dust sources, they are represented on the maps pursuant to 326 IAC 6-5-5(a).

Indiana Gasification, LLC is responsible for the execution this plan.

Description of Control Measures to be Used

Barge Unloading [EU-012A]

Coal received by barge will be unloaded by a crane and hopper arrangement mounted on a floating barge. The crane will swivel and dump the material into the surge hopper. Because the crane is on a floating barge and swivels to unload coal from a barge onto land, the most appropriate control measure is wet suppression. Water sprays will be used on an “as-needed” basis to reduce fugitive coal dust emissions. Also, the hopper into which the coal is dropped will be partially enclosed. It will have an open top for accepting the coal, but the sides will be higher than the level of the feedstock (coal) inside which will serve to help contain emissions. Wet suppression with water sprays and partial enclosure are the only practical methods of control for this type of source.

Dozer Activities on Piles [EU-012P and EU-012Q]

Fugitive coal dust emissions from dozer activities on piles will be controlled by wet suppression and compaction. Due to the large size of the piles, they can’t reasonably be enclosed or controlled by any other method.

Coal/Coke Storage Piles [EU-012W and EU-012X]

The storage piles shall be sprayed with water on an “as-needed” basis to reduce fugitive coal dust emissions. In addition, compaction will be implemented on the piles to further control fugitive coal dust emissions. Due to the large size of the piles, they can’t reasonably be enclosed or controlled by any other method.

Equipment used to maintain the pile: A bull dozer or front end loader such as a Caterpillar 824H Wheel Dozer.

Paved Plant Haul Roads [FUG-ROAD]

The number and mix of vehicular traffic on plant haul roads is anticipated to be as follows:

- Coal/Coke Haul Trucks: Max. 187 trucks per day, Avg. 36,800 trucks/year, average 25.7 tons/truck.
- Other haul vehicles/parking lots: Equivalent to Max. 83 trucks per day, average 19.7 tons/truck.

Fugitive dust emissions from vehicular traffic on paved plant haul roads will be controlled on an “as-needed” basis by the use of:

1. Paving all plant roads;
2. Use of wet suppression;
3. Prompt cleanup of any spilled materials that may create fugitive dust; and
4. Pursuant to 326 IAC 6-5-4(e), fugitive particulate matter emissions resulting from transportation of aggregate material by truck, front end loaders, or similar vehicles shall be controlled using one or more of the following measures:

    a. Use of completely enclosed vehicles;
    b. Tarping the vehicle;
    c. Maintaining the vehicle body in such a condition that prevents leaks of aggregate material;
    d. Spraying the materials in the vehicle with a suitable and effective dust suppressant; or
    e. An alternate measure.

Slag Handling Storage Pad [EU-034A] and Front-end Loader on the Slag Storage Pad [EU-034C]

Fugitive dust emissions from the Slag Handling Storage Pad and Front-end Loader on the Slag Storage Pad shall be controlled on an “as-needed” basis by wet suppression.

Equipment used to maintain the pile: A bull dozer or front end loader such as a Caterpillar 824H Wheel Dozer.

Dust Suppressant Material

For the above controls which specify the use of wet suppression, Indiana Gasification currently plans to use water. Prior to using any chemical suppressant (with or instead of water), Indiana Gasification will provide the specifications for that material to IDEM OAQ for review and approval.

Recordkeeping

Records shall be kept and maintained which document all control measures and activities to be implemented in accordance with the approved control plan. Said records shall be available upon the request of the commissioner, and shall be retained for three (3) years.

Compliance Schedule

For the fugitive coal dust sources subject to Subpart Y, this plan shall be fully implemented upon startup pursuant to Subpart Y. For sources subject to 326 IAC 6-5, this plan shall be implemented when the facility commences operation.

For the fugitive coal dust sources subject to Subpart Y, this plan shall be revised as needed to reflect any changing conditions at the facility. Such revisions will be dated and submitted to the Indiana Department of Environmental Management before operation pursuant to the revisions. For sources subject to 326 IAC 6-5, this plan shall be updated at the time of reapplication for the source's operation permit or as required in 326 IAC 2.

Attachment A to a PSD/Part 70 Operating Permit

40 CFR 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595   When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611   By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612   By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP

emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(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:

$$F_o = \frac{0.209\,F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, 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_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d\,\frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) 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;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous

compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE 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. The owner or operator 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 RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645   What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that

is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660   In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665   What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670   Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

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 fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE 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 RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

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

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-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 reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than

to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB	a. Reduce CO emissions by 93 percent or more; or	

stationary RICE		
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	**You must meet the following operating limitation . . .**
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO	Comply with any operating limitations approved by the Administrator.

emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or	

	annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every	

	1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated.

Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63— Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	

3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of	

	operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours	

	of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the	You must . . .

	requirement to . . .	
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each .	**Complying with**	**You must . . .**	**Using . . .**	**According to the following**

. .	the requirement to . . .			requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, see §63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[ab] (incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. Reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than	(a) Formaldehyde 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.

			or equal to 130	
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde 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.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	(a) CO 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] You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and

Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to

major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and

emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission

		limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and

emergency CI stationary RICE >500 HP located at a major source of HAP		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major	a. Reduce formaldehyde emissions and not using	i. Collecting the approved operating parameter (if any) data according to

source of HAP	NSCR	§63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling

		averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and

		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit

			the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4) i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).	
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the	

		gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.	
		c. Any problems or errors suspected with the meters. i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing	Yes.	

	sources		
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.

§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	

§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS	No	Subpart ZZZZ does not contain

	data		opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	

§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

Attachment B to a PSD/Part 70 Operating Permit

Standards of Performance for Coal Preparation and Processing Plants
[40 CFR Part 60, Subpart Y] [326 IAC 12]

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart Y—Standards of Performance for Coal Preparation and Processing Plants

Source: 74 FR 51977, Oct. 8, 2009, unless otherwise noted.

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected facilities in coal preparation and processing plants that process more than 181 megagrams (Mg) (200 tons) of coal per day.

(b) The provisions in §60.251, §60.252(a), §60.253(a), §60.254(a), §60.255(a), and §60.256(a) of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after October 27, 1974, and on or before April 28, 2008: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(c) The provisions in §60.251, §60.252(b)(1) and (c), §60.253(b), §60.254(b), §60.255(b) through (h), §60.256(b) and (c), §60.257, and §60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after April 28, 2008, and on or before May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), and coal storage systems, transfer and loading systems.

(d) The provisions in §60.251, §60.252(b)(1) through (3), and (c), §60.253(b), §60.254(b) and (c), §60.255(b) through (h), §60.256(b) and (c), §60.257, and §60.258 of this subpart are applicable to any of the following affected facilities that commenced construction, reconstruction or modification after May 27, 2009: Thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles.

§ 60.251 Definitions.

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

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

(b) *Bag leak detection system* means a system that is capable of continuously monitoring relative particulate matter (dust loadings) in the exhaust of a fabric filter to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

(c) *Bituminous coal* means solid fossil fuel classified as bituminous coal by ASTM D388 (incorporated by reference— *see* §60.17).

(d) *Coal* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* §60.17).

(2) For units constructed, reconstructed, or modified after May 27, 2009, all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference— *see* §60.17), and coal refuse.

(e) *Coal preparation and processing 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.

(f) *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. Equipment located at the mine face is not considered to be part of the coal preparation and processing plant.

(g) *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.

(h) *Coal storage system* means any facility used to store coal except for open storage piles.

(i) *Design controlled potential PM emissions rate* means the theoretical particulate matter (PM) emissions (Mg) that would result from the operation of a control device at its design emissions rate (grams per dry standard cubic meter (g/dscm)), multiplied by the maximum design flow rate (dry standard cubic meter per minute (dscm/min)), multiplied by 60 (minutes per hour (min/hr)), multiplied by 8,760 (hours per year (hr/yr)), divided by 1,000,000 (megagrams per gram (Mg/g)).

(j) *Indirect thermal dryer* means a thermal dryer that reduces the moisture content of coal through indirect heating of the coal through contact with a heat transfer medium. If the source of heat (the source of combustion or furnace) is subject to another subpart of this part, then the furnace and the associated emissions are not part of the affected facility. However, if the source of heat is not subject to another subpart of this part, then the furnace and the associated emissions are part of the affected facility.

(k) *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).

(l) *Mechanical vent* means any vent that uses a powered mechanical drive (machine) to induce air flow.

(m) *Open storage pile* means any facility, including storage area, that is not enclosed that is used to store coal, including the equipment used in the loading, unloading, and conveying operations of the facility.

(n) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which coal is prepared or processed at any time by the affected facility. It is not necessary that coal be prepared or processed the entire 24-hour period.

(o) *Pneumatic coal-cleaning equipment* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility which classifies coal by size or separates coal from refuse by application of air stream(s).

(p) *Potential combustion concentration* means the theoretical emissions (nanograms per joule (ng/J) or pounds per million British thermal units (lb/MMBtu) heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems, as determined using Method 19 of appendix A–7 of this part.

(q) *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).

(r) *Thermal dryer* means:

(1) For units constructed, reconstructed, or modified on or before May 27, 2009, 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.

(2) For units constructed, reconstructed, or modified after May 27, 2009, any facility in which the moisture content of coal is reduced by either contact with a heated gas stream which is exhausted to the atmosphere or through indirect heating of the coal through contact with a heated heat transfer medium.

(s) *Transfer and loading system* means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for thermal dryers.

(a) On and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified on or before April 28, 2008, subject to the provisions of this subpart must meet the requirements in paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which contain PM in excess of 0.070 g/dscm (0.031 grains per dry standard cubic feet (gr/dscf)); and

(2) The owner or operator shall not cause to be discharged into the atmosphere from the thermal dryer any gases which exhibit 20 percent opacity or greater.

(b) Except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after April 28, 2008, subject to the provisions of this subpart must meet the applicable standards for PM and opacity, as specified in paragraph (b)(1) of this section. In addition, and except as provided in paragraph (c) of this section, on and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of a thermal dryer constructed, reconstructed, or modified after May 29, 2009, subject to the provisions of this subpart must also meet the applicable standards for sulfur dioxide (SO_2), and combined nitrogen oxides (NO_X) and carbon monoxide (CO) as specified in paragraphs (b)(2) and (b)(3) of this section.

(1) The owner or operator must meet the requirements for PM emissions in paragraphs (b)(1)(i) through (iii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed or reconstructed after April 28, 2008, the owner or operator must meet the requirements of (b)(1)(i)(A) and (b)(1)(i)(B).

(A) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that contain PM in excess of 0.023 g/dscm (0.010 grains per dry standard cubic feet (gr/dscf)); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the thermal dryer any gases that exhibit 10 percent opacity or greater.

(ii) For each thermal dryer modified after April 28, 2008, the owner or operator must meet the requirements of paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B) of this section.

(A) The owner or operator must not cause to be discharged to the atmosphere from the affected facility any gases which contain PM in excess of 0.070 g/dscm (0.031 gr/dscf); and

(B) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 20 percent opacity or greater.

(2) Except as provided in paragraph (b)(2)(iii) of this section, for each thermal dryer constructed, reconstructed, or modified after May 27, 2009, the owner or operator must meet the requirements for SO_2 emissions in either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 85 ng/J (0.20 lb/MMBtu) heat input; or

(ii) The owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases that either contain SO_2 in excess of 520 ng/J (1.20 lb/MMBtu) heat input or contain SO_2 in excess of 10 percent of the potential combustion concentration (*i.e.,* the facility must achieve at least a 90 percent reduction of the potential combustion concentration and may not exceed a maximum emissions rate of 1.2 lb/MMBtu (520 ng/J)).

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to an SO_2 limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input are not subject to the SO_2 limits of this section.

(3) Except as provided in paragraph (b)(3)(iii) of this section, the owner or operator must meet the requirements for combined NO_X and CO emissions in paragraph (b)(3)(i) or (b)(3)(ii) of this section, as applicable to the affected facility.

(i) For each thermal dryer constructed after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain a combined concentration of NO_X and CO in excess of 280 ng/J (0.65 lb/MMBtu) heat input.

(ii) For each thermal dryer reconstructed or modified after May 27, 2009, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which contain combined concentration of NO_X and CO in excess of 430 ng/J (1.0 lb/MMBtu) heat input.

(iii) Thermal dryers that receive all of their thermal input from a source other than coal or residual oil, that receive all of their thermal input from a source subject to a NO_X limit and/or CO limit under another subpart of this part, or that use waste heat or residual from the combustion of coal or residual oil as their only thermal input, are not subject to the combined NO_X and CO limits of this section.

(c) Thermal dryers receiving all of their thermal input from an affected facility covered under another 40 CFR Part 60 subpart must meet the applicable requirements in that subpart but are not subject to the requirements in this subpart.

§ 60.253 Standards for pneumatic coal-cleaning equipment.

(a) On and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified on or before April 28, 2008, must meet the requirements of paragraphs (a)(1) and (a)(2) of this section.

(1) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess of 0.040 g/dscm (0.017 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit 10 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of pneumatic coal-cleaning equipment constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) The owner of operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that contain PM in excess or 0.023 g/dscm (0.010 gr/dscf); and

(2) The owner or operator must not cause to be discharged into the atmosphere from the pneumatic coal-cleaning equipment any gases that exhibit greater than 5 percent opacity.

§ 60.254 Standards for coal processing and conveying equipment, coal storage systems, transfer and loading systems, and open storage piles.

(a) On and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator 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 constructed, reconstructed, or modified on or before April 28, 2008, gases which exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test is conducted or required to be completed under §60.8, whichever date comes first, an owner or operator of any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal constructed, reconstructed, or modified after April 28, 2008, must meet the requirements in paragraphs (b)(1) through (3) of this section, as applicable to the affected facility.

(1) Except as provided in paragraph (b)(3) of this section, the owner or operator must not cause to be discharged into the atmosphere from the affected facility any gases which exhibit 10 percent opacity or greater.

(2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf).

(3) Equipment used in the loading, unloading, and conveying operations of open storage piles are not subject to the opacity limitations of paragraph (b)(1) of this section.

(c) The owner or operator of an open storage pile, which includes the equipment used in the loading, unloading, and conveying operations of the affected facility, constructed, reconstructed, or modified after May 27, 2009, must prepare and operate in accordance with a submitted fugitive coal dust emissions control plan that is appropriate for the site conditions as specified in paragraphs (c)(1) through (6) of this section.

(1) The fugitive coal dust emissions control plan must identify and describe the control measures the owner or operator will use to minimize fugitive coal dust emissions from each open storage pile.

(2) For open coal storage piles, the fugitive coal dust emissions control plan must require that one or more of the following control measures be used to minimize to the greatest extent practicable fugitive coal dust: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source (when the provisions of paragraph (c)(6) of this section are met), use of a wind barrier, compaction, or use of a vegetative cover. The owner or operator must select, for inclusion in the fugitive coal dust emissions control plan, the control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Any owner or operator of an affected facility that is required to have a fugitive coal dust emissions control plan may petition the Administrator to approve, for inclusion in the plan for the affected facility, alternative control measures other than those specified in paragraph (c)(2) of this section as specified in paragraphs (c)(3)(i) through (iv) of this section.

(i) The petition must include a description of the alternative control measures, a copy of the fugitive coal dust emissions control plan for the affected facility that includes the alternative control measures, and information sufficient for EPA to evaluate the demonstrations required by paragraph (c)(3)(ii) of this section.

(ii) The owner or operator must either demonstrate that the fugitive coal dust emissions control plan that includes the alternate control measures will provide equivalent overall environmental protection or demonstrate that it is either economically or technically infeasible for the affected facility to use the control measures specifically identified in paragraph (c)(2).

(iii) While the petition is pending, the owner or operator must comply with the fugitive coal dust emissions control plan including the alternative control measures submitted with the petition. Operation in accordance with the plan submitted with the petition shall be deemed to constitute compliance with the requirement to operate in accordance with a fugitive coal dust emissions control plan that contains one of the control measures specifically identified in paragraph (c)(2) of this section while the petition is pending.

(iv) If the petition is approved by the Administrator, the alternative control measures will be approved for inclusion in the fugitive coal dust emissions control plan for the affected facility. In lieu of amending this subpart, a letter will be sent to the facility describing the specific control measures approved. The facility shall make any such letters and the applicable fugitive coal dust emissions control plan available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(4) The owner or operator must submit the fugitive coal dust emissions control plan to the Administrator or delegated authority as specified in paragraphs (c)(4)(i) and (c)(4)(ii) of this section.

(i) The plan must be submitted to the Administrator or delegated authority prior to startup of the new, reconstructed, or modified affected facility, or 30 days after the effective date of this rule, whichever is later.

(ii) The plan must be revised as needed to reflect any changing conditions at the source. Such revisions must be dated and submitted to the Administrator or delegated authority before a source can operate pursuant to these revisions. The Administrator or delegated authority may also object to such revisions as specified in paragraph (c)(5) of this section.

(5) The Administrator or delegated authority may object to the fugitive coal dust emissions control plan as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) The Administrator or delegated authority may object to any fugitive coal dust emissions control plan that it has determined does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(ii) If an objection is raised, the owner or operator, within 30 days from receipt of the objection, must submit a revised fugitive coal dust emissions control plan to the Administrator or delegated authority. The owner or operator must operate in accordance with the revised fugitive coal dust emissions control plan. The Administrator or delegated authority retain the right, under paragraph (c)(5) of this section, to object to the revised control plan if it determines the plan does not meet the requirements of paragraphs (c)(1) and (c)(2) of this section.

(6) Where appropriate chemical dust suppression agents are selected by the owner or operator as a control measure to minimize fugitive coal dust emissions, (1) only chemical dust suppressants with Occupational Safety and Health Administration (OSHA)-compliant material safety data sheets (MSDS) are to be allowed; (2) the MSDS must be included in the fugitive coal dust emissions control plan; and (3) the owner or operator must consider and document in the fugitive coal dust emissions control plan the site-specific impacts associated with the use of such chemical dust suppressants.

§ 60.255 Performance tests and other compliance requirements.

(a) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using the methods identified in §60.257.

(b) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of §60.8 and the methods identified in §60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section.

(1) For each affected facility subject to a PM, SO_2, or combined $NO_X$and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable.

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.

(2) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section.

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed.

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed.

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in §60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests.

(c) If any affected coal processing and conveying equipment (*e.g.,* breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in *§* 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards.

(d) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers.

(1) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit,

(2) The control device manufacturer's recommended maintenance procedures are followed, and

(3) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed.

(e) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard;

(2) The manufacturer's recommended maintenance procedures are followed for each control device; and

(3) A performance test is conducted on each affected facility at least once every 5 calendar years.

(f) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section.

(1) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

(i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in §2.3 of Method 22 of appendix A–7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A–4 of this part, performance test must be conducted within 45 operating days.

(ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(iii) Conduct a performance test using Method 9 of appendix A–4 of this part at least once every 5 calendar years for each affected facility.

(2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, *see* OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.

(g) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section.

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

(2) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section.

(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For 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.

(ii) The owner or operator 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.

(iii) The owner or operator 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.

(iv) 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.

(v) The owner or operator 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.

(h) The owner or operator of each affected coal truck dump operation that commenced construction, reconstruction, or modification after April 28, 2008, must meet the requirements specified in paragraphs (h)(1) through (3) of this section.

(1) Conduct an initial performance test using Method 9 of appendix A–4 of this part according to the requirements in paragraphs (h)(1)(i) and(ii).

(i) Opacity readings shall be taken during the duration of three separate truck dump events. Each truck dump event commences when the truck bed begins to elevate and concludes when the truck bed returns to a horizontal position.

(ii) Compliance with the applicable opacity limit is determined by averaging all 15-second opacity readings made during the duration of three separate truck dump events.

(2) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible.

(3) Conduct a performance test using Method 9 of appendix A–4 of this part at least once every 5 calendar years for each affected facility.

§ 60.256   Continuous monitoring requirements.

(a) The owner or operator of each affected facility constructed, reconstructed, or modified on or before April 28, 2008, must meet the monitoring requirements specified in paragraphs (a)(1) and (2) of this section, as applicable to the affected facility.

(1) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(i) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±1.7 °C (±3 °F).

(ii) For affected facilities that use wet scrubber emission control equipment:

(A) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(B) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator shall have discretion to grant requests for approval of alternative monitoring locations.

(2) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under §60.13(b).

(b) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1) through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent.

(1) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section.

(2) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section.

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gauge.

(ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply flow rate.

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design pH.

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(3) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis.

(c) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section.

(1) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less.

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

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

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

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

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

(2) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

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

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

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

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

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

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

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

(ii) Sealing off defective bags or filter media;

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

(iv) Sealing off a defective fabric filter compartment;

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

(vi) Shutting down the process producing the PM emissions.

§ 60.257 Test methods and procedures.

(a) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section.

(1) Method 9 of appendix A–4 of this part and the procedures in §60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii).

(i) The duration of the Method 9 of appendix A–4 of this part performance test shall be 1 hour (ten 6-minute averages).

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A–4 of this part performance test, all of the 6-minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes.

(2) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used.

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back.

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction.

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission.

(3) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met.

(i) No more than three emissions points may be read concurrently.

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point.

(b) The owner or operator must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emissions standards specified in §60.252 according to the requirements in §60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section.

(1) Method 1 or 1A of appendix A–4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A–4 of this part shall be used to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B of appendix A–4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses (incorporated by reference— *see* §60.17) as an alternative to Method 3B of appendix A–2 of this part.

(4) Method 4 of appendix A–4 of this part shall be used to determine the moisture content of the stack gas.

(5) Method 5, 5B or 5D of appendix A–4 of this part or Method 17 of appendix A–7 of this part shall be used to determine the PM concentration as follows:

(i) 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. A minimum of three valid test runs are needed to comprise a PM performance test.

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(iv) Method 5D of appendix A–4 of this part shall be used for positive pressure fabric filters and other similar applications (*e.g.,* stub stacks and roof vents).

(v) Method 17 of appendix A–6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used in Method 17 of appendix A–6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A–6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(6) Method 6, 6A, or 6C of appendix A–4 of this part shall be used to determine the SO_2concentration. A minimum of three valid test runs are needed to comprise an SO_2performance test.

(7) Method 7 or 7E of appendix A–4 of this part shall be used to determine the NO_Xconcentration. A minimum of three valid test runs are needed to comprise an NO_Xperformance test.

(8) Method 10 of appendix A–4 of this part shall be used to determine the CO concentration. A minimum of three valid test runs are needed to comprise a CO performance test. CO performance tests are conducted concurrently (or within a 60-minute period) with NO_Xperformance tests.

§ 60.258 Reporting and recordkeeping.

(a) The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following:

(1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted.

(2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted.

(3) The amount and type of coal processed each calendar month.

(4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant.

(5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted.

(6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, *e.g.* objections, to the plan and any actions relative to the alternative control measures, *e.g.* approvals, shall be noted in the logbook as well.

(7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section.

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

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

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

(8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted.

(9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid.

(10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable.

(b) For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow:

(1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test.

(2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test.

(3) All 6-minute average opacities that exceed the applicable standard.

(c) The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical.

(d) After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.* For performance tests that cannot be entered into WebFIRE (*i.e.,* Method 9 of appendix A–4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243–01; RTP, NC 27711.

Attachment C to a PSD/Part 70 Operating Permit

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Db] [326 IAC 12]

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 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) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_Xstandards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_Xstandards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_Xstandards under this subpart and the PM and SO_2standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NO_Xstandards under this subpart and the SO_2standards under subpart J (§60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the $NO_X$and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(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) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(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).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 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 not meeting the definition of natural gas, 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) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline 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_2control 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 a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

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/hr-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); or

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

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_2emissions (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. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion 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 heats any 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, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission 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 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion 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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s= SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (or 1.2 lb/MMBtu);

K_b= 340 ng/J (or 0.80 lb/MMBtu);

H_a= Heat input from the combustion of coal, in J (MMBtu); and

H_b= Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the 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 on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s= SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c= 260 ng/J (or 0.60 lb/MMBtu);

K_d= 170 ng/J (or 0.40 lb/MMBtu);

H_c= Heat input from the combustion of coal, in J (MMBtu); and

H_d= Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2control system is not being operated because of malfunction or maintenance of the SO_2control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(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_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2in 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 or natural gas.

(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_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) 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 combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) 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 can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) 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 commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences 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 both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) 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 modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) 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 modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) 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, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) 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, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.44b   Standard for nitrogen oxides (NOX).

(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 (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(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) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(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:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

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) Except as provided under paragraph (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 coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) 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 natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (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 coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula 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 affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_Xemission 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, distillate oil and gaseous byproduct/waste, J (MMBtu);

EL_{ro}= Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, 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).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_Xemission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_Xemissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_Xemission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_Xemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_Xemission limit will be established at the NO_Xemission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_Xemissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_Xlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_Xemission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_Xemissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_Xemission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_Xemission limits of this section. The NO_Xemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_Xlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_Xstandards 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) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_Xemission limits under this section.

(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, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 86 ng/J (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 on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n= NO_Xemission 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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2control system 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_2emission rate (% P_s) and the SO_2emission rate (E_s) 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 30 consecutive operating days of the steam generating unit. Compliance with the SO_2standards 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) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A–7 of this part are used to determine the hourly SO_2emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO_2emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

%P_s= Potential SO_2emission rate, percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2emission rate (E_{ho}^{o}) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^{o}). The Eho° is computed using the following formula:

$$E_{ho}^{\circ} = \frac{E_{ho} - E_{w}(1 - X_{k})}{X_{k}}$$

Where:

E_{ho}^{o} = Adjusted hourly SO_2emission rate, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k= Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2emission rate ($\%P_s$), an adjusted $\%R_g$($\%R_g^{o}$) is computed from the adjusted E_{ao}^{o} from paragraph (b)(3)(i) of this section and an adjusted average SO_2inlet rate (E_{ai}^{o}) using the following formula:

$$\%R_{g}^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

To compute E_{ai}^{o} , an adjusted hourly SO_2inlet rate (E_{hi}^{o}) is used. The E_{hi}^{o} is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_{w}(1 - X_{k})}{X_{k}}$$

Where:

E_{hi}^{o} = Adjusted hourly SO_2inlet rate, ng/J (lb/MMBtu); and

E_{hi}= Hourly SO_2inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters $E_w$or $X_k$if the owner or operator elects to assume that X_k= 1.0. Owners or operators of affected facilities who assume X_k= 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A–7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(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 $\%P_s$ or E_s 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 only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard 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 in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 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) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(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) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A–2 of this part is used for gas analysis when applying Method 5 of appendix A–3 of this part or Method 17 of appendix A–6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A–6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used in Method 17 of appendix A–6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A–6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(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 NO_X 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) Following the date on which the initial performance test is completed or is required to be completed in §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under §60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in §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 for 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.

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

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

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

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad (Eq.1)$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg}= Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g= Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b= Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g= Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_X and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made 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 start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A–3 of this part, or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) 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 notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

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

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input 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.

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

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs 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 continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For O_2(or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) 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.

(13) 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 75 percent of total operating hours per 30-day rolling average.

(14) After July 1, 2011, within 90 days after completing a correlation testing run, the owner or operator of an affected facility shall either successfully enter the test data into EPA's WebFIRE data base located at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §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, E_D, 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 greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(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_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(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).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

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

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), or (5) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

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

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

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

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.46d(d)(7).

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

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_Xstandard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate 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_Xemission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. 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_Xemission rates measured by the continuous NO_Xmonitor 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) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(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_Xspan values shall be determined as follows:

Fuel	**Span values for NO_X (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) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_X standards in §60.44b(a)(4), §60.44b(e), or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), or (6) of this section is not required to install or operate a COMS 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 §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; or

(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 §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. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(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 uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part; or

(6) 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 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) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) 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.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 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_Xemission 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 NO_Xstandard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. 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_Xemission 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_2level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_Xemission 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(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) 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.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_Xstandards 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_Xemission 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; and

(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) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

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

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

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

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

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(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) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(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 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; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), 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 §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, 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 reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(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) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_Xemission limit shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b(i).

(iii) The monitoring of the NO_Xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_Xstandard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_Xburner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_Xemission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_Xemission limit shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b.

(iii) The monitoring of the NO_Xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_Xtechnology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_Xemissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(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) Facility-specific NO_Xstandard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_Xemission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_Xemissions shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b.

(ii) The monitoring of the NO_Xemissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_Xstandard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO* $_X$. (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO* $_X$. (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009]

Attachment D to a PSD/Part 70 Operating Permit

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR Part 60, Subpart Kb] [326 IAC 12]

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b   Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.117b Delegation of authority.

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

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Attachment E to a PSD/Part 70 Operating Permit

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 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) and other persons as specified in paragraphs (a)(1) through (4) 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) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(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) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

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?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 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;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later 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.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

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?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder 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 must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 9.0 · $n^{-0.20}$g/KW-hr (6.7 · $n^{-0.20}$g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (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).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§ 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 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 engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 45 · $n^{-0.2}$g/KW-hr (34 · $n^{-0.2}$g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 44 · $n^{-0.23}$g/KW-hr (33 · $n^{-0.23}$g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 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 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

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 purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(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) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) 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 (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 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 that does not meet the standards applicable to non-emergency engines, 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.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 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 do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) 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 emission-related specifications, except as permitted in paragraph (g) of this section.

(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) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) 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. The owner or operator 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. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as permitted in this section, is prohibited.

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you

change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011]

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 (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(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.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 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 (f) 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_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_Xor 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_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

%O_2= Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

%CO_2= Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad (\text{Eq. }7)$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_X concentration in ppm.

1.912×10^{-3}= Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad (\text{Eq. }8)$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(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?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 45 · $n^{-0.2}$g/KW-hr (34 · $n^{-0.2}$g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) 44 · $n^{-0.23}$g/KW-hr (33 · $n^{-0.23}$g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216   What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§ 60.4217   What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

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.

Certified emissions 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 certified emissions 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 certified emissions 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).

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.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

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.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

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 the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes 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.

(2) 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 manufactured (see “date of manufacture”).

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, aircraft, 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.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

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≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤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]

	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)			
Engine power	**Model year(s)**	**NO_X+ NMHC**	**CO**	**PM**
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤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

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)[1]**
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1] Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

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
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010–2012, manufacturers, owners and operators 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 2009 model year engines.

[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≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤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 the inlet and outlet of the control device;	(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 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 stationary CI internal combustion	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.

	engine exhaust.			
		ii. Determine the O_2concentration 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_2concentration must be made at the same time as the measurement for NO_Xconcentration.
		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_Xconcentration.
		iv. Measure NO_Xat 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 reference, see §60.17)	(d) NO_Xconcentration 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.
	c. Reduce PM emissions by 60 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_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must

		and outlet of the control device; and		be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM 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.
	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_2concentration 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_2concentration 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 internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM 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.

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	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§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	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§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	

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Attachment F to a PSD/Part 70 Operating Permit

Leak detection and Repair (LDAR) Conditions for All Fugitive Sources -Subpart H— National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks [40 CFR Part 63, Subpart H] [326 IAC 20]

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Subpart H—National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

Source: 59 FR 19568, Apr. 22, 1994, unless otherwise noted.

§ 63.160 Applicability and designation of source.

(a) The provisions of this subpart apply to pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed vent systems required by this subpart that are intended to operate in organic hazardous air pollutant service 300 hours or more during the calendar year within a source subject to the provisions of a specific subpart in 40 CFR part 63 that references this subpart.

(b) After the compliance date for a process unit, equipment to which this subpart applies that are also subject to the provisions of:

(1) 40 CFR part 60 will be required to comply only with the provisions of this subpart.

(2) 40 CFR part 61 will be required to comply only with the provisions of this subpart.

(c) If a process unit subject to the provisions of this subpart has equipment to which this subpart does not apply, but which is subject to a standard identified in paragraph (c)(1), (c)(2), or (c)(3) of this section, the owner or operator may elect to apply this subpart to all such equipment in the process unit. If the owner or operator elects this method of compliance, all VOC in such equipment shall be considered, for purposes of applicability and compliance with this subpart, as if it were organic hazardous air pollutant (HAP). Compliance with the provisions of this subpart, in the manner described in this paragraph, shall be deemed to constitute compliance with the standard identified in paragraph (c)(1), (c)(2), or (c)(3) of this section.

(1) 40 CFR part 60, subpart VV, GGG, or KKK; (2) 40 CFR part 61, subpart F or J; or (3) 40 CFR part 264, subpart BB or 40 CFR part 265, subpart BB.

(2) [Reserved]

(d) The provisions in §63.1(a)(3) of subpart A of this part do not alter the provisions in paragraph (b) of this section.

(e) Except as provided in any subpart that references this subpart, lines and equipment not containing process fluids are not subject to the provisions of this subpart. Utilities, and other non-process lines, such as heating and cooling systems which do not combine their materials with those in the processes they serve, are not considered to be part of a process unit.

(f) The provisions of this subpart do not apply to research and development facilities or to bench-scale batch processes, regardless of whether the facilities or processes are located at the same plant site as a process subject to the provisions of this subpart.

(g) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators of CMPU that are subject to §63.100 may choose to comply with the provisions of 40 CFR part 65 for all Group 1 and Group 2 process vents, Group 1 storage vessels, Group 1 transfer operations, and equipment that are subject to §63.100, that are part of the CMPU. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) For equipment, 40 CFR part 65 satisfies the requirements of §§63.102, 63.103, and 63.162 through 63.182. When choosing to comply with 40 CFR part 65, the requirements of §63.180(d) continue to apply.

(ii) For Group 1 and Group 2 process vents, Group 1 storage vessels, and Group 1 transfer operations, comply with §63.110(i)(1).

(2) *Part 65, subpart C or F.* For owners or operators choosing to comply with 40 CFR part 65, each surge control vessel and bottoms receiver subject to §63.100 that meets the conditions specified in table 2 or table 3 of this subpart shall meet the requirements for storage vessels in 40 CFR part 65, subpart C; all other equipment subject to §63.100 shall meet the requirements in 40 CFR part 65, subpart F.

(3) *Part 63, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C or F, for equipment subject to §63.100 must also comply with the applicable general provisions of this part 63 listed in table 4 of this subpart. All sections and paragraphs of subpart A of this part that are not mentioned in table 4 of this subpart do not apply to owners or operators of equipment subject to §63.100 of subpart F complying with 40 CFR part 65, subpart C or F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C or F, must comply with 40 CFR part 65, subpart A.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 59 FR 53360, Oct. 24, 1994; 60 FR 18029, Apr. 10, 1995; 61 FR 31439, June 20, 1996; 64 FR 20198, Apr. 26, 1999; 65 FR 78285, Dec. 14, 2000]

§ 63.161 Definitions.

All terms used in this subpart shall have the meaning given them in the Act and in this section as follows, except as provided in any subpart that references this subpart.

Batch process means a process in which the equipment is fed intermittently or discontinuously. Processing then occurs in this equipment after which the equipment is generally emptied. Examples of industries that use batch processes include pharmaceutical production and pesticide production.

Batch product-process equipment train means the collection of equipment (e.g., connectors, reactors, valves, pumps, etc.) configured to produce a specific product or intermediate by a batch process.

Bench-scale batch process means a batch process (other than a research and development facility) that is operated on a small scale, such as one capable of being located on a laboratory bench top. This bench-scale equipment will typically include reagent feed vessels, a small reactor and associated product separator, recovery and holding equipment. These processes are only capable of producing small quantities of product.

Bottoms receiver means a tank that collects distillation bottoms before the stream is sent for storage or for further downstream processing.

Closed-loop system means an enclosed system that returns process fluid to the process and is not vented to the atmosphere except through a closed-vent system.

Closed-purge system means a system or combination of system and portable containers, to capture purged liquids. Containers must be covered or closed when not being filled or emptied.

Closed-vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back into a process.

Combustion device means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of organic hazardous air pollutant emissions.

Compliance date means the dates specified in §63.100(k) or §63.100(l)(3) of subpart F of this part for process units subject to subpart F of this part; the dates specified in §63.190(e) of subpart I of this part for process units subject to subpart I of this part. For sources subject to other subparts in 40 CFR part 63 that reference this subpart, compliance date will be defined in those subparts. However, the compliance date for §63.170 shall be no later than 3 years after the effective date of those subparts unless otherwise specified in such other subparts.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation. For the purpose of reporting and recordkeeping, connector means joined fittings that are not inaccessible, glass, or glass-lined as described in §63.174(h) of this subpart.

Control device means any equipment used for recovering, recapturing, or oxidizing organic hazardous air pollutant vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, flares, boilers, and process heaters.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, bottoms receiver, and instrumentation system in organic hazardous air pollutant service; and any control devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere, followed by monitoring as specified in §63.180 (b) and (c), as appropriate, to verify whether the leak is repaired, unless the owner or operator determines by other means that the leak is not repaired.

Flow indicator means a device which indicates whether gas flow is, or whether the valve position would allow gas flow to be, present in a line.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in in-process combustion equipment such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgement and standards, such as ANSI B31–3.

In food/medical service means that a piece of equipment in organic hazardous air pollutant service contacts a process stream used to manufacture a Food and Drug Administration regulated product where leakage of a barrier fluid into the process stream would cause any of the following:

(1) A dilution of product quality so that the product would not meet written specifications,

(2) An exothermic reaction which is a safety hazard,

(3) The intended reaction to be slowed down or stopped, or

(4) An undesired side reaction to occur.

In gas/vapor service means that a piece of equipment in organic hazardous air pollutant service contains a gas or vapor at operating conditions.

In heavy liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service or in light liquid service.

In light liquid service means that a piece of equipment in organic hazardous air pollutant service contains a liquid that meets the following conditions:

(1) The vapor pressure of one or more of the organic compounds is greater than 0.3 kilopascals at 20 °C,

(2) The total concentration of the pure organic compounds constituents having a vapor pressure greater than 0.3 kilopascals at 20 °C is equal to or greater than 20 percent by weight of the total process stream, and

(3) The fluid is a liquid at operating conditions.

Note: Vapor pressures may be determined by the methods described in 40 CFR 60.485(e)(1).

In liquid service means that a piece of equipment in organic hazardous air pollutant service is not in gas/vapor service.

In organic hazardous air pollutant or *in organic HAP service* means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d) of this subpart. The provisions of §63.180(d) of this subpart also specify how to determine that a piece of equipment is not in organic HAP service.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals below ambient pressure.

In volatile organic compound or *in VOC service* means, for the purposes of this subpart, that:

(1) The piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight (see 40 CFR 60.2 for the definition of VOC, and 40 CFR 60.485(d) to determine whether a piece of equipment is not in VOC service); and

(2) The piece of equipment is not in heavy liquid service as defined in 40 CFR 60.481.

In-situ sampling systems means nonextractive samplers or in-line samplers.

Initial start-up means the first time a new or reconstructed source begins production. Initial start-up does not include operation solely for testing equipment. Initial start-up does not include subsequent start-ups (as defined in this section) of process units following malfunctions or process unit shutdowns.

Instrumentation system means a group of equipment components used to condition and convey a sample of the process fluid to analyzers and instruments for the purpose of determining process operating conditions (e.g., composition, pressure, flow, etc.). Valves and connectors are the predominant type of equipment used in instrumentation systems; however, other types of equipment may also be included in these systems. Only valves nominally 0.5 inches and smaller, and connectors nominally 0.75 inches and smaller in diameter are considered instrumentation systems for the purposes of this subpart. Valves greater than nominally 0.5 inches and connectors greater than nominally 0.75 inches associated with instrumentation systems are not considered part of instrumentation systems and must be monitored individually.

Liquids dripping means any visible leakage from the seal including dripping, spraying, misting, clouding, and ice formation. Indications of liquid dripping include puddling or new stains that are indicative of an existing evaporated drip.

Nonrepairable means that it is technically infeasible to repair a piece of equipment from which a leak has been detected without a process unit shutdown.

On-site or *On site* means, with respect to records required to be maintained by this subpart, that the records are stored at a location within a major source which encompasses the affected source. On-site includes, but is not limited to, storage at the chemical manufacturing process unit to which the records pertain, or storage in central files elsewhere at the major source.

Open-ended valve or line means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Plant site means all contiguous or adjoining property that is under common control, including properties that are separated only by a road or other public right-of-way. Common control includes properties that are owned, leased, or operated by the same entity, parent entity, subsidiary, or any combination thereof.

Polymerizing monomer means a molecule or compound usually containing carbon and of relatively low molecular weight and simple structure (e.g., hydrogen cyanide, acrylonitrile, styrene), which is capable of conversion to polymers, synthetic resins, or elastomers by combination with itself due to heat generation caused by a pump mechanical seal surface, contamination by a seal fluid (e.g., organic peroxides or chemicals that will form organic peroxides), or a combination of both with the resultant polymer buildup causing rapid mechanical seal failure.

Pressure release means the emission of materials resulting from the system pressure being greater than the set pressure of the pressure relief device. This release can be one release or a series of releases over a short time period due to a malfunction in the process.

Pressure relief device or valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Process unit means a chemical manufacturing process unit as defined in subpart F of this part, a process subject to the provisions of subpart I of this part, or a process subject to another subpart in 40 CFR part 63 that references this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be effected. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown, is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

Recapture device means an individual unit of equipment capable of and used for the purpose of recovering chemicals, but not normally for use, reuse, or sale. Recapture devices include, but are not limited to, absorbers, carbon absorbers, and condensers.

Recovery device means an individual unit of equipment capable of and normally used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse, or for sale for fuel value, use or reuse. Recovery devices include, but are not limited to, absorbers, carbon absorbers, and condensers. For purposes of the monitoring, recordkeeping, and reporting requirements of this subpart, recapture devices are considered recovery devices.

Repaired means that equipment:

(1) Is adjusted, or otherwise altered, to eliminate a leak as defined in the applicable sections of this subpart, and

(2) Unless otherwise specified in applicable provisions of this subpart, is monitored as specified in §63.180 (b) and (c), as appropriate, to verify that emissions from the equipment are below the applicable leak definition.

Routed to a process or route to a process means the emissions are conveyed by hard-piping or a closed vent system to any enclosed portion of a process unit where the emissions are predominately recycled and/or consumed in the same manner as a material that fulfills the same function in the process; and/or transformed by chemical reaction into materials that are not organic hazardous air pollutants; and/or incorporated into a product; and/or recovered.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take non-routine grab samples is not considered a sampling connection system.

Screwed connector means a threaded pipe fitting where the threads are cut on the pipe wall and the fitting requires only two pieces to make the connection (i.e., the pipe and the fitting).

Sensor means a device that measures a physical quantity or the change in a physical quantity, such as temperature, pressure, flow rate, pH, or liquid level.

Set pressure means the pressure at which a properly operating pressure relief device begins to open to relieve atypical process system operating pressure.

Start-up means the setting in operation of a piece of equipment or a control device that is subject to this subpart.

Surge control vessel means feed drums, recycle drums, and intermediate vessels. Surge control vessels are used within a process unit (as defined in the specific subpart that references this subpart) when in-process storage, mixing, or management of flow rates or volumes is needed to assist in production of a product.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 60 FR 18024, 18029, Apr. 10, 1995; 61 FR 31439, June 20, 1996; 62 FR 2788, Jan. 17, 1997]

§ 63.162 Standards: General.

(a) Compliance with this subpart will be determined by review of the records required by §63.181 of this subpart and the reports required by §63.182 of this subpart, review of performance test results, and by inspections.

(b)(1) An owner or operator may request a determination of alternative means of emission limitation to the requirements of §§63.163 through 63.170, and §§63.172 through 63.174 of this subpart as provided in §63.177.

(2) If the Administrator makes a determination that a means of emission limitation is a permissible alternative to the requirements of §§63.163 through 63.170, and §§63.172 through 63.174 of this subpart, the owner or operator shall comply with the alternative.

(c) Each piece of equipment in a process unit to which this subpart applies shall be identified such that it can be distinguished readily from equipment that is not subject to this subpart. Identification of the equipment does not require physical tagging of the equipment. For example, the equipment may be identified on a plant site plan, in log entries, or by designation of process unit boundaries by some form of weatherproof identification.

(d) Equipment that is in vacuum service is excluded from the requirements of this subpart.

(e) Equipment that is in organic HAP service less than 300 hours per calendar year is excluded from the requirements of §§63.163 through 63.174 of this subpart and §63.178 of this subpart if it is identified as required in §63.181(j) of this subpart.

(f) When each leak is detected as specified in §§63.163 and 63.164; §§63.168 and 63.169; and §§63.172 through 63.174 of this subpart, the following requirements apply:

(1) Clearly identify the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored as specified in §§63.168(f)(3), and 63.175(e)(7)(i)(D) of this subpart, and no leak has been detected during the follow-up monitoring. If the owner or operator elects to comply using the provisions of §63.174(c)(1)(i) of this subpart, the identification on a connector may be removed after it is monitored as specified in §63.174(c)(1)(i) and no leak is detected during that monitoring.

(3) The identification which has been placed on equipment determined to have a leak, except for a valve or for a connector that is subject to the provisions of §63.174(c)(1)(i), may be removed after it is repaired.

(g) Except as provided in paragraph (g)(1) of this section, all terms in this subpart that define a period of time for completion of required tasks (e.g., weekly, monthly, quarterly, annual), refer to the standard calendar periods unless specified otherwise in the section or subsection that imposes the requirement.

(1) If the initial compliance date does not coincide with the beginning of the standard calendar period, an owner or operator may elect to utilize a period beginning on the compliance date, or may elect to comply in accordance with the provisions of paragraphs (g)(2) or (g)(3) of this section.

(2) Time periods specified in this subpart for completion of required tasks may be changed by mutual agreement between the owner or operator and the Administrator, as specified in subpart A of this part. For each time period that is changed by agreement, the revised period shall remain in effect until it is changed. A new request is not necessary for each recurring period.

(3) Except as provided in paragraph (g)(1) or (g)(2) of this section, where the period specified for compliance is a standard calendar period, if the initial compliance date does not coincide with the beginning of the calendar period, compliance shall be required according to the schedule specified in paragraphs (g)(3)(i) or (g)(3)(ii) of this section, as appropriate.

(i) Compliance shall be required before the end of the standard calendar period within which the compliance deadline occurs, if there remain at least 3 days for tasks that must be performed weekly, at least 2 weeks for tasks that must be performed monthly, at least 1 month for tasks that must be performed each quarter, or at least 3 months for tasks that must be performed annually; or

(ii) In all other cases, compliance shall be required before the end of the first full standard calendar period after the period within which the initial compliance deadline occurs.

(4) In all instances where a provision of this subpart requires completion of a task during each of multiple successive periods, an owner or operator may perform the required task at any time during each period, provided the task is conducted at a reasonable interval after completion of the task during the previous period.

(h) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this subpart to fail to take action to repair the leaks within the specified time. If action is taken to repair the leaks within the specified time, failure of that action to successfully repair the leak is not a violation of this subpart. However, if the repairs are unsuccessful, a leak is detected and the owner or operator shall take further action as required by applicable provisions of this subpart.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 62 FR 2789, Jan. 17, 1997; 68 FR 37345, June 23, 2003]

§ 63.163 Standards: Pumps in light liquid service.

(a) The provisions of this section apply to each pump that is in light liquid service.

(1) The provisions are to be implemented on the dates specified in the specific subpart in 40 CFR part 63 that references this subpart in the phases specified below:

(i) For each group of existing process units at existing sources subject to the provisions of subparts F or I of this part, the phases of the standard are:

(A) Phase I, beginning on the compliance date;

(B) Phase II, beginning no later than 1 year after the compliance date; and

(C) Phase III, beginning no later than 21/2years after the compliance date.

(ii) For new sources subject to the provisions of subparts F or I of this part, the applicable phases of the standard are:

(A) After initial start-up, comply with the Phase II requirements; and

(B) Beginning no later than 1 year after initial start-up, comply with the Phase III requirements.

(2) The owner or operator of a source subject to the provisions of subparts F or I of this part may elect to meet the requirements of a later phase during the time period specified for an earlier phase.

(3) Sources subject to other subparts in 40 CFR part 63 that reference this subpart shall comply on the dates specified in the applicable subpart.

(b)(1) The owner or operator of a process unit subject to this subpart shall monitor each pump monthly to detect leaks by the method specified in §63.180(b) of this subpart and shall comply with the requirements of paragraphs (a) through (d) of this section, except as provided in §63.162(b) of this subpart and paragraphs (e) through (j) of this section.

(2) The instrument reading, as determined by the method as specified in §63.180(b) of this subpart, that defines a leak in each phase of the standard is:

(i) For Phase I, an instrument reading of 10,000 parts per million or greater.

(ii) For Phase II, an instrument reading of 5,000 parts per million or greater.

(iii) For Phase III, an instrument reading of:

(A) 5,000 parts per million or greater for pumps handling polymerizing monomers;

(B) 2,000 parts per million or greater for pumps in food/medical service; and

(C) 1,000 parts per million or greater for all other pumps.

(3) Each pump shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal. If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in paragraph (c)(3) of this section or §63.171 of this subpart.

(2) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected. First attempts at repair include, but are not limited to, the following practices where practicable:

(i) Tightening of packing gland nuts.

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(3) For pumps in Phase III to which a 1,000 parts per million leak definition applies, repair is not required unless an instrument reading of 2,000 parts per million or greater is detected.

(d)(1) The owner or operator shall decide no later than the first monitoring period whether to calculate percent leaking pumps on a process unit basis or on a source-wide basis. Once the owner or operator has decided, all subsequent percent calculations shall be made on the same basis.

(2) If, in Phase III, calculated on a 6-month rolling average, the greater of either 10 percent of the pumps in a process unit or three pumps in a process unit leak, the owner or operator shall implement a quality improvement program for pumps that complies with the requirements of §63.176 of this subpart.

(3) The number of pumps at a process unit shall be the sum of all the pumps in organic HAP service, except that pumps found leaking in a continuous process unit within 1 month after start-up of the pump shall not count in the percent leaking pumps calculation for that one monitoring period only.

(4) Percent leaking pumps shall be determined by the following equation:

$$\%P_L=((P_L-P_S)/(P_T-P_S))\times100$$

where:

$\%P_L$=Percent leaking pumps

P_L=Number of pumps found leaking as determined through monthly monitoring as required in paragraphs (b)(1) and (b)(2) of this section.

P_T=Total pumps in organic HAP service, including those meeting the criteria in paragraphs (e) and (f) of this section.

P_S=Number of pumps leaking within 1 month of start-up during the current monitoring period.

(e) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraphs (a) through (d) of this section, provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed-vent system to a control device that complies with the requirements of §63.172 of this subpart; or

(iii) Equipped with a closed-loop system that purges the barrier fluid into a process stream.

(2) The barrier fluid is not in light liquid service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(i) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the pump shall be monitored as specified in §63.180(b) of this subpart to determine if there is a leak of organic HAP in the barrier fluid.

(ii) If an instrument reading of 1,000 parts per million or greater is measured, a leak is detected.

(5) Each sensor as described in paragraph (e)(3) of this section is observed daily or is equipped with an alarm unless the pump is located within the boundary of an unmanned plant site.

(6)(i) The owner or operator determines, based on design considerations and operating experience, criteria applicable to the presence and frequency of drips and to the sensor that indicates failure of the seal system, the barrier fluid system, or both.

(ii) If indications of liquids dripping from the pump seal exceed the criteria established in paragraph (e)(6)(i) of this section, or if, based on the criteria established in paragraph (e)(6)(i) of this section, the sensor indicates failure of the seal system, the barrier fluid system, or both, a leak is detected.

(iii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §63.171 of this subpart.

(iv) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(f) Any pump that is designed with no externally actuated shaft penetrating the pump housing is exempt from the requirements of paragraphs (a) through (c) of this section.

(g) Any pump equipped with a closed-vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §63.172 of this subpart is exempt from the requirements of paragraphs (b) through (e) of this section.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (b)(3) and (e)(4) of this section, and the daily requirements of paragraph (e)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

(i) If more than 90 percent of the pumps at a process unit meet the criteria in either paragraph (e) or (f) of this section, the process unit is exempt from the requirements of paragraph (d) of this section.

(j) Any pump that is designated, as described in §63.181(b)(7)(i) of this subpart, as an unsafe-to-monitor pump is exempt from the requirements of paragraphs (b) through (e) of this section if:

(1) The owner or operator of the pump determines that the pump is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b) through (d) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practical during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 61 FR 31439, June 20, 1996; 62 FR 2789, Jan. 17, 1997; 64 FR 20198, Apr. 26, 1999]

§ 63.164 Standards: Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of process fluid to the atmosphere, except as provided in §63.162(b) of this subpart and paragraphs (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed-vent system to a control device that complies with the requirements of §63.172 of this subpart; or

(3) Equipped with a closed-loop system that purges the barrier fluid directly into a process stream.

(c) The barrier fluid shall not be in light liquid service.

(d) Each barrier fluid system as described in paragraphs (a) through (c) of this section shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be observed daily or shall be equipped with an alarm unless the compressor is located within the boundary of an unmanned plant site.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §63.171 of this subpart.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) through (g) of this section if it is equipped with a closed-vent system to capture and transport leakage from the compressor drive shaft seal back to a process or a fuel gas system or to a control device that complies with the requirements of §63.172 of this subpart.

(i) Any compressor that is designated, as described in §63.181(b)(2)(ii) of this subpart, to operate with an instrument reading of less than 500 parts per million above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with an instrument reading of less than 500 parts per million above background, as measured by the method specified in §63.180(c) of this subpart; and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 62 FR 2790, Jan. 17, 1997; 64 FR 20198, Apr. 26, 1999]

§ 63.165 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with an instrument reading of less than 500 parts per million above background except as provided in paragraph (b) of this section, as measured by the method specified in §63.180(c) of this subpart.

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition indicated by an instrument reading of less than 500 parts per million above background, as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §63.171 of this subpart.

(2) No later than 5 calendar days after the pressure release and being returned to organic HAP service, the pressure relief device shall be monitored to confirm the condition indicated by an instrument reading of less than 500 parts per million above background, as measured by the method specified in §63.180(c) of this subpart.

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed-vent system capable of capturing and transporting leakage from the pressure relief device to a control device as described in §63.172 of this subpart is exempt from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §63.171 of this subpart.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 62 FR 2790, Jan. 17, 1997]

§ 63.166 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §63.162(b) of this subpart. Gases displaced during filling of the sample container are not required to be collected or captured.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall:

(1) Return the purged process fluid directly to the process line; or

(2) Collect and recycle the purged process fluid to a process; or

(3) Be designed and operated to capture and transport the purged process fluid to a control device that complies with the requirements of §63.172 of this subpart; or

(4) Collect, store, and transport the purged process fluid to a system or facility identified in paragraph (b)(4)(i), (ii), or (iii) of this section.

(i) A waste management unit as defined in §63.111 of subpart G of this part, if the waste management unit is subject to, and operated in compliance with the provisions of subpart G of this part applicable to group 1 wastewater streams. If the purged process fluid does not contain any organic HAP listed in Table 9 of subpart G of part 63, the waste management unit need not be subject to, and operated in compliance with the requirements of 40 CFR part 63, subpart G applicable to group 1 wastewater streams provided the facility has an NPDES permit or sends the wastewater to an NPDES permitted facility.

(ii) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266; or

(iii) A facility permitted, licensed, or registered by a State to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261.

(c) *In-situ* sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

[59 FR 19568, Apr. 22, 1994, as amended at 61 FR 31439, June 20, 1996]

§ 63.167 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §63.162(b) of this subpart and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line, or during maintenance or repair.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block and bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b) and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or, would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraph (a) through (c) of this section.

[59 FR 19568, Apr. 22, 1994, as amended at 61 FR 31440, June 20, 1996]

§ 63.168 Standards: Valves in gas/vapor service and in light liquid service.

(a) The provisions of this section apply to valves that are either in gas service or in light liquid service.

(1) The provisions are to be implemented on the dates set forth in the specific subpart in 40 CFR part 63 that references this subpart as specified in paragraph (a)(1)(i), (a)(1)(ii), or (a)(1)(iii) of this section.

(i) For each group of existing process units at existing sources subject to the provisions of subpart F or I of this part, the phases of the standard are:

(A) Phase I, beginning on the compliance date;

(B) Phase II, beginning no later than 1 year after the compliance date; and

(C) Phase III, beginning no later than 21/2years after the compliance date.

(ii) For new sources subject to the provisions of subpart F or I of this part, the applicable phases of the standard are:

(A) After initial start-up, comply with the Phase II requirements; and

(B) Beginning no later than 1 year after initial start-up, comply with the Phase III requirements.

(iii) Sources subject to other subparts in 40 CFR part 63 that reference this subpart shall comply on the dates specified in the applicable subpart.

(2) The owner or operator of a source subject to this subpart may elect to meet the requirements of a later phase during the time period specified for an earlier phase.

(3) The use of monitoring data generated before April 22, 1994 to qualify for less frequent monitoring is governed by the provisions of §63.180(b)(6) of this subpart.

(b) The owner or operator of a source subject to this subpart shall monitor all valves, except as provided in §63.162(b) of this subpart and paragraphs (h) and (i) of this section, at the intervals specified in paragraphs (c) and (d) of this section and shall comply with all other provisions of this section, except as provided in §63.171, §63.177, §63.178, and §63.179 of this subpart.

(1) The valves shall be monitored to detect leaks by the method specified in §63.180(b) of this subpart.

(2) The instrument reading that defines a leak in each phase of the standard is:

(i) For Phase I, an instrument reading of 10,000 parts per million or greater.

(ii) For Phase II, an instrument reading of 500 parts per million or greater.

(iii) For Phase III, an instrument reading of 500 parts per million or greater.

(c) In Phases I and II, each valve shall be monitored quarterly.

(d) In Phase III, the owner or operator shall monitor valves for leaks at the intervals specified below:

(1) At process units with 2 percent or greater leaking valves, calculated according to paragraph (e) of this section, the owner or operator shall either:

(i) Monitor each valve once per month; or

(ii) Within the first year after the onset of Phase III, implement a quality improvement program for valves that complies with the requirements of §63.175 (d) or (e) of this subpart and monitor quarterly.

(2) At process units with less than 2 percent leaking valves, the owner or operator shall monitor each valve once each quarter, except as provided in paragraphs (d)(3) and (d)(4) of this section.

(3) At process units with less than 1 percent leaking valves, the owner or operator may elect to monitor each valve once every 2 quarters.

(4) At process units with less than 0.5 percent leaking valves, the owner or operator may elect to monitor each valve once every 4 quarters.

(e)(1) Percent leaking valves at a process unit shall be determined by the following equation:

$\%V_L=(V_L/(V_T+V_C))\times 100$

where:

$\%V_L$=Percent leaking valves as determined through periodic monitoring required in paragraphs (b) through (d) of this section.

V_L=Number of valves found leaking excluding nonrepairables as provided in paragraph (e)(3)(i) of this section.

V_T=Total valves monitored, in a monitoring period excluding valves monitored as required by (f)(3) of this section.

V_C=Optional credit for removed valves=0.67 × net number (i.e., total removed−total added) of valves in organic HAP service removed from process unit after the date set forth in §63.100(k) of subpart F for existing process units, and after the date of initial start-up for new sources. If credits are not taken, then V_C=0.

(2) For use in determining monitoring frequency, as specified in paragraph (d) of this section, the percent leaking valves shall be calculated as a rolling average of two consecutive monitoring periods for monthly, quarterly, or semiannual monitoring programs; and as an average of any three out of four consecutive monitoring periods for annual monitoring programs.

(3)(i) Nonrepairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and nonrepairable and as required to comply with paragraph (e)(3)(ii) of this section. Otherwise, a number of nonrepairable valves (identified and included in the percent leaking calculation in a previous period) up to a maximum of 1 percent of the total number of valves in organic HAP service at a process unit may be excluded from calculation of percent leaking valves for subsequent monitoring periods.

(ii) If the number of nonrepairable valves exceeds 1 percent of the total number of valves in organic HAP service at a process unit, the number of nonrepairable valves exceeding 1 percent of the total number of valves in organic HAP service shall be included in the calculation of percent leaking valves.

(f)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §63.171 of this subpart.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(3) When a leak has been repaired, the valve shall be monitored at least once within the first 3 months after its repair.

(i) The monitoring shall be conducted as specified in §63.180 (b) and (c), as appropriate, to determine whether the valve has resumed leaking.

(ii) Periodic monitoring required by paragraphs (b) through (d) of this section may be used to satisfy the requirements of this paragraph (f)(3), if the timing of the monitoring period coincides with the time specified in this paragraph (f)(3). Alternatively, other monitoring may be performed to satisfy the requirements of this paragraph (f)(3), regardless of whether the timing of the monitoring period for periodic monitoring coincides with the time specified in this paragraph (f)(3).

(iii) If a leak is detected by monitoring that is conducted pursuant to paragraph (f)(3) of this section, the owner or operator shall follow the provisions of paragraphs (f)(3)(iii)(A) and (f)(3)(iii)(B) of this section, to determine whether that valve must be counted as a leaking valve for purposes of §63.168(e) of this subpart.

(A) If the owner or operator elected to use periodic monitoring required by paragraphs (b) through (d) of this section to satisfy the requirements of paragraph (f)(3) of this section, then the valve shall be counted as a leaking valve.

(B) If the owner or operator elected to use other monitoring, prior to the periodic monitoring required by paragraphs (b) through (d) of this section, to satisfy the requirements of paragraph (f)(3) of this section, then the valve shall be counted as a leaking valve unless it is repaired and shown by periodic monitoring not to be leaking.

(g) First attempts at repair include, but are not limited to, the following practices where practicable:

(1) Tightening of bonnet bolts,

(2) Replacement of bonnet bolts,

(3) Tightening of packing gland nuts, and

(4) Injection of lubricant into lubricated packing.

(h) Any valve that is designated, as described in §63.181(b)(7)(i) of this subpart, as an unsafe-to-monitor valve is exempt from the requirements of paragraphs (b) through (f) of this section if:

(1) The owner or operator of the valve determines that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b) through (d) of this section; and

(2) The owner or operator of the valve has a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable.

(i) Any valve that is designated, as described in §63.181(b)(7)(ii) of this subpart, as a difficult-to-monitor valve is exempt from the requirements of paragraphs (b) through (d) of this section if:

(1) The owner or operator of the valve determines that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface or it is not accessible at anytime in a safe manner;

(2) The process unit within which the valve is located is an existing source or the owner or operator designates less than 3 percent of the total number of valves in a new source as difficult-to-monitor; and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

(j) Any equipment located at a plant site with fewer than 250 valves in organic HAP service is exempt from the requirements for monthly monitoring and a quality improvement program specified in paragraph (d)(1) of this section. Instead, the owner or operator shall monitor each valve in organic HAP service for leaks once each quarter, or comply with paragraph (d)(3) or (d)(4) of this section except as provided in paragraphs (h) and (i) of this section.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48176, Sept. 20, 1994; 61 FR 31440, June 20, 1996; 62 FR 2790, Jan. 17, 1997]

§ 63.169   Standards: Pumps, valves, connectors, and agitators in heavy liquid service; instrumentation systems; and pressure relief devices in liquid service.

(a) Pumps, valves, connectors, and agitators in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and instrumentation systems shall be monitored within 5 calendar days by the method specified in §63.180(b) of this subpart if evidence of a potential leak to the atmosphere is found by visual, audible, olfactory, or any other detection method. If such a potential leak is repaired as required in paragraphs (c) and (d) of this section, it is not necessary to monitor the system for leaks by the method specified in §63.180(b) of this subpart.

(b) If an instrument reading of 10,000 parts per million or greater for agitators, 5,000 parts per million or greater for pumps handling polymerizing monomers, 2,000 parts per million or greater for all other pumps (including pumps in food/medical service), or 500 parts per million or greater for valves, connectors, instrumentation systems, and pressure relief devices is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §63.171 of this subpart.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(3) For equipment identified in paragraph (a) of this section that is not monitored by the method specified in §63.180(b), repaired shall mean that the visual, audible, olfactory, or other indications of a leak to the atmosphere have been eliminated; that no bubbles are observed at potential leak sites during a leak check using soap solution; or that the system will hold a test pressure.

(d) First attempts at repair include, but are not limited to, the practices described under §§63.163(c)(2) and 63.168(g) of this subpart, for pumps and valves, respectively.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 60 FR 18029, Apr. 10, 1995; 62 FR 2790, Jan. 17, 1997; 65 FR 78285, Dec. 14, 2000]

§ 63.170 Standards: Surge control vessels and bottoms receivers.

Each surge control vessel or bottoms receiver that is not routed back to the process and that meets the conditions specified in table 2 or table 3 of this subpart shall be equipped with a closed-vent system that routes the organic vapors vented from the surge control vessel or bottoms receiver back to the process or to a control device that complies with the requirements in §63.172 of this subpart, except as provided in §63.162(b) of this subpart, or comply with the requirements of §63.119(b) or (c) of subpart G of this part.

[60 FR 18024, Apr. 10, 1995]

§ 63.171 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected is allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur by the end of the next process unit shutdown.

(b) Delay of repair of equipment for which leaks have been detected is allowed for equipment that is isolated from the process and that does not remain in organic HAP service.

(c) Delay of repair for valves, connectors, and agitators is also allowed if:

(1) The owner or operator determines that emissions of purged material resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §63.172 of this subpart.

(d) Delay of repair for pumps is also allowed if:

(1) Repair requires replacing the existing seal design with a new system that the owner or operator has determined under the provisions of §63.176(d) of this subpart will provide better performance or:

(i) A dual mechanical seal system that meets the requirements of §63.163(e) of this subpart,

(ii) A pump that meets the requirements of §63.163(f) of this subpart, or

(iii) A closed-vent system and control device that meets the requirements of §63.163(g) of this subpart; and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the second process unit shutdown will not be allowed unless the third process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 65 FR 78285, Dec. 14, 2000]

§ 63.172 Standards: Closed-vent systems and control devices.

(a) Owners or operators of closed-vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section, except as provided in §63.162(b) of this subpart.

(b) Recovery or recapture devices (e.g., condensers and absorbers) shall be designed and operated to recover the organic hazardous air pollutant emissions or volatile organic compounds emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts par million by volume, whichever is less stringent. The 20 parts per million by volume performance standard is not applicable to the provisions of §63.179.

(c) Enclosed combustion devices shall be designed and operated to reduce the organic hazardous air pollutant emissions or volatile organic compounds emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent, or to provide a minimum residence time of 0.50 seconds at a minimum temperature of 760 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §63.11(b) of subpart A of this part.

(e) Owners or operators of control devices that are used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.

Note: The intent of this provision is to ensure proper operation and maintenance of the control device.

(f) Except as provided in paragraphs (k) and (l) of this section, each closed-vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If the closed-vent system is constructed of hard-piping, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in paragraph (g) of this section, and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed-vent system is constructed of duct work, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in paragraph (g) of this section, and

(ii) Conduct annual inspections according to the procedures in paragraph (g) of this section.

(g) Each closed-vent system shall be inspected according to the procedures in §63.180(b) of this subpart.

(h) Leaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual inspections, shall be repaired as soon as practicable, except as provided in paragraph (i) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected, except as provided in paragraph (i) of this section.

(i) Delay of repair of a closed-vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(j) For each closed-vent system that contains bypass lines that could divert a vent stream away from the control device and to the atmosphere, the owner or operator shall comply with the provisions of either paragraph (j)(1) or (j)(2) of this section, except as provided in paragraph (j)(3) of this section.

(1) Install, set or adjust, maintain, and operate a flow indicator that takes a reading at least once every 15 minutes. Records shall be generated as specified in §63.118(a)(3) of subpart G of this part. The flow indicator shall be installed at the entrance to any bypass line; or

(2) Secure the bypass line valve in the non-diverting position with a car-seal or a lock-and-key type configuration. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass line.

(3) Equipment such as low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and pressure relief valves needed for safety purposes are not subject to this paragraph.

(k) Any parts of the closed-vent system that are designated, as described in paragraph 63.181(b)(7)(i), as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1) and (f)(2) of this section if:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraph (f)(1) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times, but not more frequently than annually.

(l) Any parts of the closed-vent system that are designated, as described in §63.181 (b)(7)(i) of this subpart, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1) and (f)(2) of this section if:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years.

(m) Whenever organic HAP emissions are vented to a closed-vent system or control device used to comply with the provisions of this subpart, such system or control device shall be operating.

(n) After the compliance dates specified in §63.100 of subpart F of this part, the owner or operator of any control device subject to this subpart that is also subject to monitoring, recordkeeping, and reporting requirements in 40 CFR part 264, subpart BB, or is subject to monitoring and recordkeeping requirements in 40 CFR part 265, subpart BB, may elect to comply either with the monitoring, recordkeeping, and reporting requirements of this subpart, or with the monitoring, recordkeeping, and reporting requirements in 40 CFR parts 264 and/or 265, as described in this paragraph, which shall constitute compliance with the monitoring, recordkeeping and reporting requirements of this subpart. The owner or operator shall identify which option has been chosen, in the next periodic report required by §63.182(d).

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 61 FR 31440, June 20, 1996; 62 FR 2790, Jan. 17, 1997]

§ 63.173 Standards: Agitators in gas/vapor service and in light liquid service.

(a)(1) Each agitator shall be monitored monthly to detect leaks by the methods specified in §63.180(b) of this subpart, except as provided in §63.162(b) of this subpart.

(2) If an instrument reading of 10,000 parts per million or greater is measured, a leak is detected.

(b)(1) Each agitator shall be checked by visual inspection each calendar week for indications of liquids dripping from the agitator.

(2) If there are indications of liquids dripping from the agitator, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §63.171 of this subpart.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each agitator equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (d)(6) of this section are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the agitator stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed-vent system to a control device that complies with the requirements of §63.172 of this subpart; or

(iii) Equipped with a closed-loop system that purges the barrier fluid into a process stream.

(2) The barrier fluid is not in light liquid organic HAP service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each agitator is checked by visual inspection each calendar week for indications of liquids dripping from the agitator seal.

(i) If there are indications of liquids dripping from the agitator seal at the time of the weekly inspection, the agitator shall be monitored as specified in §63.180(b) of this subpart to determine the presence of organic HAP in the barrier fluid.

(ii) If an instrument reading of 10,000 parts per million or greater is measured, a leak is detected.

(5) Each sensor as described in paragraph (d)(3) of this section is observed daily or is equipped with an alarm unless the agitator is located within the boundary of an unmanned plant site.

(6)(i) The owner or operator determines, based on design considerations and operating experience, criteria applicable to the presence and frequency of drips and to the sensor that indicates failure of the seal system, the barrier fluid system, or both.

(ii) If indications of liquids dripping from the agitator seal exceed the criteria established in paragraph (d)(6)(i) of this section, or if, based on the criteria established in paragraph (d)(6)(i) of this section, the sensor indicates failure of the seal system, the barrier fluid system, or both, a leak is detected.

(iii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §63.171 of this subpart.

(iv) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any agitator that is designed with no externally actuated shaft penetrating the agitator housing is exempt from paragraphs (a) through (c) of this section.

(f) Any agitator equipped with a closed-vent system capable of capturing and transporting any leakage from the seal or seals to a process or fuel gas system or to a control device that complies with the requirements of §63.172 of this subpart is exempt from the requirements of paragraphs (a) through (c) of the section.

(g) Any agitator that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (b)(1) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each agitator is visually inspected as often as practical and at least monthly.

(h) Any agitator that is difficult-to-monitor is exempt from the requirements of paragraphs (a) through (d) of this section if:

(1) The owner or operator determines that the agitator cannot be monitored without elevating the monitoring personnel more than two meters above a support surface or it is not accessible at anytime in a safe manner;

(2) The process unit within which the agitator is located is an existing source or the owner or operator designates less than three percent of the total number of agitators in a new source as difficult-to-monitor; and

(3) The owner or operator follows a written plan that requires monitoring of the agitator at least once per calendar year.

(i) Any agitator that is obstructed by equipment or piping that prevents access to the agitator by a monitor probe is exempt from the monitoring requirements of paragraphs (a) through (d) of this section.

(j) Any agitator that is designated, as described in §63.181(b)(7)(i) of this subpart, as an unsafe-to-monitor agitator is exempt from the requirements of paragraphs (a) through (d) of this section if:

(1) The owner or operator of the agitator determines that the agitator is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) through (d) of this section; and

(2) The owner or operator of the agitator has a written plan that requires monitoring of the agitator as frequently as practical during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable.

[59 FR 19568, Apr. 22, 1994, as amended at 61 FR 31440, June 20, 1996; 62 FR 2791, Jan. 17, 1997; 64 FR 20198, Apr. 26, 1999]

§ 63.174 Standards: Connectors in gas/vapor service and in light liquid service.

(a) The owner or operator of a process unit subject to this subpart shall monitor all connectors in gas/vapor and light liquid service, except as provided in §63.162(b) of this subpart, and in paragraphs (f) through (h) of this section, at the intervals specified in paragraph (b) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in §63.180(b) of this subpart.

(2) If an instrument reading greater than or equal to 500 parts per million is measured, a leak is detected.

(b) The owner or operator shall monitor for leaks at the intervals specified in either paragraph (b)(1) or (b)(2) of this section and in paragraph (b)(3) of this section.

(1) For each group of existing process units within an existing source, by no later than 12 months after the compliance date, the owner or operator shall monitor all connectors, except as provided in paragraphs (f) through (h) of this section.

(2) For new sources, within the first 12 months after initial start-up or by no later than 12 months after the date of promulgation of a specific subpart that references this subpart, whichever is later, the owner or operator shall monitor all connectors, except as provided in paragraphs (f) through (h) of this section.

(3) After conducting the initial survey required in paragraph (b)(1) or (b)(2) of this section, the owner or operator shall perform all subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(3)(i) through (b)(3)(v) of this section, except as provided in paragraph (c)(2) of this section:

(i) Once per year (i.e., 12-month period), if the percent leaking connectors in the process unit was 0.5 percent or greater during the last required annual or biennial monitoring period.

(ii) Once every 2 years, if the percent leaking connectors was less than 0.5 percent during the last required monitoring period. An owner or operator may comply with this paragraph by monitoring at least 40 percent of the connectors in the first year and the remainder of the connectors in the second year. The percent leaking connectors will be calculated for the total of all monitoring performed during the 2-year period.

(iii) If the owner or operator of a process unit in a biennial leak detection and repair program calculates less than 0.5 percent leaking connectors from the 2-year monitoring period, the owner or operator may monitor the connectors one time every 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 20 percent of the connectors each year until all connectors have been monitored within 4 years.

(iv) If a process unit complying with the requirements of paragraph (b) of this section using a 4-year monitoring interval program has greater than or equal to 0.5 percent but less than 1 percent leaking connectors, the owner or operator shall increase the monitoring frequency to one time every 2 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors in the first year and the remainder of the connectors in the second year. The owner or operator may again elect to use the provisions of paragraph (b)(3)(iii) of this section when the percent leaking connectors decreases to less than 0.5 percent.

(v) If a process unit complying with requirements of paragraph (b)(3)(iii) of this section using a 4-year monitoring interval program has 1 percent or greater leaking connectors, the owner or operator shall increase the monitoring frequency to one time per year. The owner or operator may again elect to use the provisions of paragraph (b)(3)(iii) of this section when the percent leaking connectors decreases to less than 0.5 percent.

(4) The use of monitoring data generated before April 22, 1994 to qualify for less frequent monitoring is governed by the provisions of §63.180(b)(6).

(c)(1)(i) Except as provided in paragraph (c)(1)(ii) of this section, each connector that has been opened or has otherwise had the seal broken shall be monitored for leaks when it is reconnected or within the first 3 months after being returned to organic hazardous air pollutants service. If the monitoring detects a leak, it shall be repaired according to the provisions of paragraph (d) of this section, unless it is determined to be nonrepairable, in which case it is counted as a nonrepairable connector for the purposes of paragraph (i)(2) of this section.

(ii) As an alternative to the requirements in paragraph (c)(1)(i) of this section, an owner or operator may choose not to monitor connectors that have been opened or otherwise had the seal broken. In this case, the owner or operator may not count nonrepairable connectors for the purposes of paragraph (i)(2) of this section. The owner or operator shall calculate the percent leaking connectors for the monitoring periods described in paragraph (b) of this section, by setting the nonrepairable component, C_{AN}, in the equation in paragraph (i)(2) of this section to zero for all monitoring periods.

(iii) An owner or operator may switch alternatives described in paragraphs (c)(1) (i) and (ii) of this section at the end of the current monitoring period he is in, provided that it is reported as required in §63.182 of this subpart and begin the new alternative in annual monitoring. The initial monitoring in the new alternative shall be completed no later than 12 months after reporting the switch.

(2) As an alternative to the requirements of paragraph (b)(3) of this section, each screwed connector 2 inches or less in nominal inside diameter installed in a process unit before the dates specified in paragraph (c)(2)(iii) or (c)(2)(iv) of this section may:

(i) Comply with the requirements of §63.169 of this subpart, and

(ii) Be monitored for leaks within the first 3 months after being returned to organic hazardous air pollutants service after having been opened or otherwise had the seal broken. If that monitoring detects a leak, it shall be repaired according to the provisions of paragraph (d) of this section.

(iii) For sources subject to subparts F and I of this part, the provisions of paragraph (c)(2) of this section apply to screwed connectors installed before December 31, 1992.

(iv) For sources not identified in paragraph (c)(2)(iii) of this section, the provisions of paragraph (c)(2) of this section apply to screwed connectors installed before the date of proposal of the applicable subpart of this part that references this subpart.

(d) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in paragraph (g) of this section and in §63.171 of this subpart. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(e) [Reserved]

(f) Any connector that is designated, as described in §63.181(b)(7)(i) of this subpart, as an unsafe-to-monitor connector is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator determines that the connector is unsafe to monitor because personnel would be exposed to an immediate danger as a result of complying with paragraphs (a) through (e) of this section; and

(2) The owner or operator has a written plan that requires monitoring of the connector as frequently as practicable during safe to monitor periods, but not more frequently than the periodic schedule otherwise applicable.

(g) Any connector that is designated, as described in §63.181(b)(7)(iii) of this subpart, as an unsafe-to-repair connector is exempt from the requirements of paragraphs (a), (d), and (e) of this section if:

(1) The owner or operator determines that repair personnel would be exposed to an immediate danger as a consequence of complying with paragraph (d) of this section; and

(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(h)(1) Any connector that is inaccessible or is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (c) of this section and from the recordkeeping and reporting requirements of §63.181 and §63.182 of this subpart. An inaccessible connector is one that is:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold which would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible or ceramic or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the leak shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §63.171 of this subpart and paragraph (g) of this section.

(3) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(i) For use in determining the monitoring frequency, as specified in paragraph (b) of this section, the percent leaking connectors shall be calculated as specified in paragraphs (i)(1) and (i)(2) of this section.

(1) For the first monitoring period, use the following equation:

$\% C_L = C_L/(C_t + C_C) \times 100$

where:

$\% C_L$= Percent leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b) of this section.

C_L= Number of connectors measured at 500 parts per million or greater, by the method specified in §63.180(b) of this subpart.

C_t= Total number of monitored connectors in the process unit.

C_C= Optional credit for removed connectors = 0.67 × net (i.e., total removed—total added) number of connectors in organic hazardous air pollutants service removed from the process unit after the compliance date set forth in the applicable subpart for existing process units, and after the date of initial start-up for new process units. If credits are not taken, then C_C= 0.

(2) For subsequent monitoring periods, use the following equation:

$\% C_L = [(C_L - C_{AN})/(C_t + C_C)] \times 100$

where:

$\% C_L$= Percent leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b) of this section.

C_L= Number of connectors, including nonrepairables, measured at 500 parts per million or greater, by the method specified in §63.180(b) of this subpart.

C_{AN}= Number of allowable nonrepairable connectors, as determined by monitoring required in paragraphs (b)(3) and (c) of this section, not to exceed 2 percent of the total connector population, C_t.

C_t= Total number of monitored connectors, including nonrepairables, in the process unit.

C_C= Optional credit for removed connectors = 0.67 × net number (i.e., total removed—total added) of connectors in organic hazardous air pollutants service removed from the process unit after the compliance date set forth in the applicable subpart for existing process units, and after the date of initial start-up for new process units. If credits are not taken, then C_C= 0.

(j) Optional credit for removed connectors. If an owner or operator eliminates a connector subject to monitoring under paragraph (b) of this section, the owner or operator may receive credit for elimination of the connector, as described in paragraph (i) of this section, provided the requirements in paragraphs (j)(1) through (j)(4) are met.

(1) The connector was welded after the date of proposal of the specific subpart that references this subpart.

(2) The integrity of the weld is demonstrated by monitoring it according to the procedures in §63.180(b) of this subpart or by testing using X-ray, acoustic monitoring, hydrotesting, or other applicable method.

(3) Welds created after the date of proposal but before the date of promulgation of a specific subpart that references this subpart are monitored or tested by 3 months after the compliance date specified in the applicable subpart.

(4) Welds created after promulgation of the subpart that references this subpart are monitored or tested within 3 months after being welded.

(5) If an inadequate weld is found or the connector is not welded completely around the circumference, the connector is not considered a welded connector and is therefore not exempt from the provisions of this subpart.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 61 FR 31440, June 20, 1996; 62 FR 2791, Jan. 17, 1997]

§ 63.175 Quality improvement program for valves.

(a) In Phase III, an owner or operator may elect to comply with one of the alternative quality improvement programs specified in paragraphs (d) and (e) of this section. The decision to use one of these alternative provisions to comply with the requirements of §63.168(d)(1)(ii) of this subpart must be made during the first year of Phase III for existing process units and for new process units.

(b) An owner or operator of a process unit subject to the requirements of paragraph (d) or (e) of this section shall comply with those requirements until the process unit has fewer than 2 percent leaking valves, calculated as a rolling average of 2 consecutive quarters, as specified in §63.168(e) of this subpart.

(c) After the process unit has fewer than 2 percent leaking valves, the owner or operator may elect to comply with the requirements in §63.168 of this subpart, to continue to comply with the requirements in paragraph (e) (or (d), if appropriate) of this section, or comply with both the requirements in §63.168 and §63.175.

(1) If the owner or operator elects to continue the quality improvement program, the owner or operator is exempt from the requirements for performance trials as specified in paragraph (e)(6) of this section, or further progress as specified in paragraph (d)(4) of this section, as long as the process unit has fewer than 2 percent leaking valves calculated according to §63.168(e).

(2) If the owner or operator elects to comply with both paragraph (e) of this section and §63.168 of this subpart, he may also take advantage of the lower monitoring frequencies associated with lower leak rates in §63.168 (d)(2), (d)(3), and (d)(4) of this subpart.

(3) If the owner or operator elects not to continue the quality improvement program, the program is no longer an option if the process unit again exceeds 2 percent leaking valves, and in such case, monthly monitoring will be required.

(d) The following requirements shall be met if an owner or operator elects to use a quality improvement program to demonstrate further progress:

(1) The owner or operator shall continue to comply with the requirements in §63.168 of this subpart except each valve shall be monitored quarterly.

(2) The owner or operator shall collect the following data, and maintain records as required in §63.181(h)(1) of this subpart, for each valve in each process unit subject to the quality improvement program:

(i) The maximum instrument reading observed in each monitoring observation before repair, the response factor for the stream if appropriate, the instrument model number, and date of the observation.

(ii) Whether the valve is in gas or light liquid service.

(iii) If a leak is detected, the repair methods used and the instrument readings after repair.

(3) The owner or operator shall continue to collect data on the valves as long as the process unit remains in the quality improvement program.

(4) The owner or operator must demonstrate progress in reducing the percent leaking valves each quarter the process unit is subject to the requirements of paragraph (d) of this section, except as provided in paragraphs (d)(4)(ii) and (d)(4)(iii) of this section.

(i) Demonstration of progress shall mean that for each quarter there is at least a 10-percent reduction in the percent leaking valves from the percent leaking valves determined for the preceding monitoring period. The percent leaking valves shall be calculated as a rolling average of two consecutive quarters of monitoring data. The percent reduction shall be calculated using the rolling average percent leaking valves, according to the following:

$\%LV_R = (\%LV_{AVG1} - \%LV_{AVG2} / \%LV_{AVG1} \times 100$

where:

$\%LV_R$=Percent leaking valve reduction.

$\%LV_{AVG1} = (\%V_{Li} + \%VLi=1)/2$.

$\%LV_{AVG2} = (\%VLi=1 + \%VLi=2)/2$.

where:

$\%V_{Li}$, %VLi=1, %VLi=2are percent leaking valves calculated for subsequent monitoring periods, i, i+1, i+2.

(ii) An owner or operator who fails for two consecutive rolling averages to demonstrate at least a 10-percent reduction per quarter in percent leaking valves, and whose overall average percent reduction based on two or more rolling averages is less than 10 percent per quarter, shall either comply with the requirements in §63.168(d)(1)(i) of this subpart using monthly monitoring or shall comply using a quality improvement program for technology review as specified in paragraph (e) of this section. If the owner or operator elects to comply with the requirements of paragraph (e) of this section, the schedule for performance trials and valve replacements remains as specified in paragraph (e) of this section.

(iii) As an alternative to the provisions in paragraph (d)(4)(i), an owner or operator may use the procedure specified in paragraphs (d)(4)(iii)(A) and (d)(4)(iii)(B) of this section to demonstrate progress in reducing the percent leaking valves.

(A) The percent reduction that must be achieved each quarter shall be calculated as follows:

$$\%RR = \frac{\%V_L - 2\%}{0.10}$$

%RR = percent reduction required each quarter, as calculated according to §63.168(e)

$\%V_L$= percent leaking valves, calculated according to §63.168(e), at the time elected to use provisions of §63.168(d)(1)(ii)

(B) The owner or operator shall achieve less than 2 percent leaking valves no later than 2 years after electing to use the demonstration of progress provisions in §63.175(d) of this subpart.

(e) The following requirements shall be met if an owner or operator elects to use a quality improvement program of technology review and improvement:

(1) The owner or operator shall comply with the requirements in §63.168 of this subpart except the requirement for monthly monitoring in §63.168(d)(1)(i) of this subpart does not apply.

(2) The owner or operator shall collect the data specified below, and maintain records as required in §63.181(h)(2), for each valve in each process unit subject to the quality improvement program. The data may be collected and the records may be maintained on a process unit or group of process units basis. The data shall include the following:

(i) Valve type (e.g., ball, gate, check); valve manufacturer; valve design (e.g., external stem or actuating mechanism, flanged body); materials of construction; packing material; and year installed.

(ii) Service characteristics of the stream such as operating pressure, temperature, line diameter, and corrosivity.

(iii) Whether the valve is in gas or light liquid service.

(iv) The maximum instrument readings observed in each monitoring observation before repair, response factor for the stream if adjusted, instrument model number, and date of the observation.

(v) If a leak is detected, the repair methods used and the instrument readings after repair.

(vi) If the data will be analyzed as part of a larger analysis program involving data from other plants or other types of process units, a description of any maintenance or quality assurance programs used in the process unit that are intended to improve emission performance.

(3) The owner or operator shall continue to collect data on the valves as long as the process unit remains in the quality improvement program.

(4) The owner or operator shall inspect all valves removed from the process unit due to leaks. The inspection shall determine which parts of the valve have failed and shall include recommendations, as appropriate, for design changes or changes in specifications to reduce leak potential.

(5)(i) The owner or operator shall analyze the data collected to comply with the requirements of paragraph (e)(2) of this section to determine the services, operating or maintenance practices, and valve designs or technologies that have poorer than average emission performance and those that have better than average emission performance. The analysis shall determine if specific trouble areas can be identified on the basis of service, operating conditions or maintenance practices, equipment design, or other process specific factors.

(ii) The analysis shall also be used to identify any superior performing valve technologies that are applicable to the service(s), operating conditions, or valve designs associated with poorer than average emission performance. A superior performing valve technology is one for which a group of such valves has a leak frequency of less than 2 percent for specific applications in such a process unit. A candidate superior performing valve technology is one demonstrated or reported in the available literature or through a group study as having low emission performance and as being capable of achieving less than 2 percent leaking valves in the process unit.

(iii) The analysis shall include consideration of:

(A) The data obtained from the inspections of valves removed from the process unit due to leaks,

(B) Information from the available literature and from the experience of other plant sites that will identify valve designs or technologies and operating conditions associated with low emission performance for specific services, and

(C) Information on limitations on the service conditions for the valve design and operating conditions as well as information on maintenance procedures to ensure continued low emission performance.

(iv) The data analysis may be conducted through an inter- or intra-company program (or through some combination of the two approaches) and may be for a single process unit, a company, or a group of process units.

(v) The first analysis of the data shall be completed no later than 18 months after the start of Phase III. The first analysis shall be performed using a minimum of two quarters of data. An analysis of the data shall be done each year the process unit is in the quality improvement program.

(6) A trial evaluation program shall be conducted at each plant site for which the data analysis does not identify superior performing valve designs or technologies that can be applied to the operating conditions and services identified as having poorer than average performance, except as provided in paragraph (e)(6)(v) of this section. The trial program shall be used to evaluate the feasibility of using in the process unit the valve designs or technologies that have been identified by others as having low emission performance.

(i) The trial program shall include on-line trials of valves or operating and maintenance practices that have been identified in the available literature or in analysis by others as having the ability to perform with leak rates below 2 percent in similar services, as having low probability of failure, or as having no external actuating mechanism in contact with the process fluid. If any of the candidate superior performing valve technologies is not included in the performance trials, the reasons for rejecting specific technologies from consideration shall be documented as required in §63.181(h)(5)(ii) of this subpart.

(ii) The number of valves in the trial evaluation program shall be the lesser of 1 percent or 20 valves for programs involving single process units and the lesser of 1 percent or 50 valves for programs involving groups of process units.

(iii) The trial evaluation program shall specify and include documentation of:

(A) The candidate superior performing valve designs or technologies to be evaluated, the stages for evaluating the identified candidate valve designs or technologies, including the estimated time period necessary to test the applicability;

(B) The frequency of monitoring or inspection of the equipment;

(C) The range of operating conditions over which the component will be evaluated; and

(D) Conclusions regarding the emission performance and the appropriate operating conditions and services for the trial valves.

(iv) The performance trials shall initially be conducted for, at least, a 6-month period beginning not later than 18 months after the start of Phase III. Not later than 24 months after the start of Phase III, the owner or operator shall have identified valve designs or technologies that, combined with appropriate process, operating, and maintenance practices, operate with low emission performance for specific applications in the process unit. The owner or operator shall continue to conduct performance trials as long as no superior performing design or technology has been identified, except as provided in paragraph (e)(6)(vi) of this section. The compilation of candidate and demonstrated superior emission performance valve designs or technologies shall be amended in the future, as appropriate, as additional information and experience is obtained.

(v) Any plant site with fewer than 400 valves and owned by a corporation with fewer than 100 total employees shall be exempt from trial evaluations of valves. Plant sites exempt from the trial evaluations of valves shall begin the program at the start of the fourth year of Phase III.

(vi) An owner or operator who has conducted performance trials on all candidate superior emission performance technologies suitable for the required applications in the process unit may stop conducting performance trials provided that a superior performing design or technology has been demonstrated or there are no technically feasible candidate superior technologies remaining. The owner or operator shall prepare an engineering evaluation documenting the physical, chemical, or engineering basis for the judgment that the superior emission performance technology is technically infeasible or demonstrating that it would not reduce emissions.

(7) Each owner or operator who elects to use a quality improvement program for technology review and improvement shall prepare and implement a valve quality assurance program that details purchasing specifications and maintenance procedures for all valves in the process unit. The quality assurance program may establish any number of categories, or classes, of valves as needed to distinguish among operating conditions and services associated with poorer than average emission performance as well as those associated with better than average emission performance. The quality assurance program shall be developed considering the findings of the data analysis required under paragraph (e)(5) of this section, if applicable, the findings of the trial evaluation required in paragraph (e)(6) of this section, and the operating conditions in the process unit. The quality assurance program shall be reviewed and, as appropriate, updated each year as long as the process unit has 2 percent or more leaking valves.

(i) The quality assurance program shall:

(A) Establish minimum design standards for each category of valves. The design standards shall specify known critical parameters such as tolerance, manufacturer, materials of construction, previous usage, or other applicable identified critical parameters;

(B) Require that all equipment orders specify the design standard (or minimum tolerances) for the valve;

(C) Include a written procedure for bench testing of valves that specifies performance criteria for acceptance of valves and specifies criteria for the precision and accuracy of the test apparatus. All valves repaired off-line after preparation of the quality assurance plan shall be bench-tested for leaks. This testing may be conducted by the owner or operator of the process unit, by the vendor, or by a designated representative. The owner or operator shall install only those valves that have been documented through bench-testing to be nonleaking.

(D) Require that all valves repaired on-line be monitored using the method specified in §63.180(b) of this subpart for leaks for 2 successive months, after repair.

(E) Provide for an audit procedure for quality control of purchased equipment to ensure conformance with purchase specifications. The audit program may be conducted by the owner or operator of the process unit or by a designated representative.

(F) Detail off-line valve maintenance and repair procedures. These procedures shall include provisions to ensure that rebuilt or refurbished valves will meet the design specifications for the valve type and will operate such that emissions are minimized.

(ii) The quality assurance program shall be established no later than the start of the third year of Phase III for plant sites with 400 or more valves or owned by a corporation with 100 or more employees; and no later than the start of the fourth year of Phase III for plant sites with less than 400 valves and owned by a corporation with less than 100 employees.

(8) Beginning at the start of the third year of Phase III for plant sites with 400 or more valves or owned by a corporation with 100 or more employees and at the start of the fourth year of Phase III for plant sites with less than 400 valves and owned by a corporation with less than 100 employees, each valve that is replaced for any reason shall be replaced with a new or modified valve that complies with the quality assurance standards for the valve category and that is identified as superior emission performance technology. Superior emission performance technology means valves or valve technologies identified with emission performance that, combined with appropriate

process, operating, and maintenance practices, will result in less than 2 percent leaking valves for specific applications in a large population, except as provided in paragraph (e)(8)(ii) of this section.

(i) The valves shall be maintained as specified in the quality assurance program.

(ii) If a superior emission performance technology cannot be identified, then valve replacement shall be with one of (if several) the lowest emission performance technologies that has been identified for the specific application.

[59 FR 19568, Apr. 22, 1994, as amended at 60 FR 63631, Dec. 12, 1995]

§ 63.176 Quality improvement program for pumps.

(a) In Phase III, if, on a 6-month rolling average, the greater of either 10 percent of the pumps in a process unit (or plant site) or three pumps in a process unit (or plant site) leak, the owner or operator shall comply with the requirements of this section as specified below:

(1) Pumps that are in food/medical service or in polymerizing monomer service shall comply with all requirements except for those specified in paragraph (d)(8) of this section.

(2) Pumps that are not in food/medical or polymerizing monomer service shall comply with all requirements of this section.

(b) The owner or operator shall comply with the requirements of this section until the number of leaking pumps is less than the greater of either 10 percent of the pumps or three pumps, calculated as a 6-month rolling average, in the process unit (or plant site). Once the performance level is achieved, the owner or operator shall comply with the requirements in §63.163 of this subpart.

(c) If in a subsequent monitoring period, the process unit (or plant site) has greater than 10 percent of the pumps leaking or three pumps leaking (calculated as a 6-month rolling average), the owner or operator shall resume the quality improvement program starting at performance trials.

(d) The quality improvement program shall include the following:

(1) The owner or operator shall comply with the requirements in §63.163 of this subpart.

(2) The owner or operator shall collect the following data, and maintain records as required in §63.181(h)(3), for each pump in each process unit (or plant site) subject to the quality improvement program. The data may be collected and the records may be maintained on a process unit or plant site basis.

(i) Pump type (e.g., piston, horizontal or vertical centrifugal, gear, bellows); pump manufacturer; seal type and manufacturer; pump design (e.g., external shaft, flanged body); materials of construction; if applicable, barrier fluid or packing material; and year installed.

(ii) Service characteristics of the stream such as discharge pressure, temperature, flow rate, corrosivity, and annual operating hours.

(iii) The maximum instrument readings observed in each monitoring observation before repair, response factor for the stream if appropriate, instrument model number, and date of the observation.

(iv) If a leak is detected, the repair methods used and the instrument readings after repair.

(v) If the data will be analyzed as part of a larger analysis program involving data from other plants or other types of process units, a description of any maintenance or quality assurance programs used in the process unit that are intended to improve emission performance.

(3) The owner or operator shall continue to collect data on the pumps as long as the process unit (or plant site) remains in the quality improvement program.

(4) The owner or operator shall inspect all pumps or pump seals which exhibited frequent seal failures and were removed from the process unit due to leaks. The inspection shall determine the probable cause of the pump seal failure or of the pump leak and shall include recommendations, as appropriate, for design changes or changes in specifications to reduce leak potential.

(5)(i) The owner or operator shall analyze the data collected to comply with the requirements of paragraph (d)(2) of this section to determine the services, operating or maintenance practices, and pump or pump seal designs or technologies that have poorer than average emission performance and those that have better than average emission performance. The analysis shall determine if specific trouble areas can be identified on the basis of service, operating conditions or maintenance practices, equipment design, or other process specific factors.

(ii) The analysis shall also be used to determine if there are superior performing pump or pump seal technologies that are applicable to the service(s), operating conditions, or pump or pump seal designs associated with poorer than average emission performance. A superior performing pump or pump seal technology is one with a leak frequency of less than 10 percent for specific applications in the process unit or plant site. A candidate superior performing pump or pump seal technology is one demonstrated or reported in the available literature or through a group study as having low emission performance and as being capable of achieving less than 10 percent leaking pumps in the process unit (or plant site).

(iii) The analysis shall include consideration of:

(A) The data obtained from the inspections of pumps and pump seals removed from the process unit due to leaks;

(B) Information from the available literature and from the experience of other plant sites that will identify pump designs or technologies and operating conditions associated with low emission performance for specific services; and

(C) Information on limitations on the service conditions for the pump seal technology operating conditions as well as information on maintenance procedures to ensure continued low emission performance.

(iv) The data analysis may be conducted through an inter- or intra-company program (or through some combination of the two approaches) and may be for a single process unit, a plant site, a company, or a group of process units.

(v) The first analysis of the data shall be completed no later than 18 months after the start of the quality improvement program. The first analysis shall be performed using a minimum of 6 months of data. An analysis of the data shall be done each year the process unit is in the quality improvement program.

(6) A trial evaluation program shall be conducted at each plant site for which the data analysis does not identify use of superior performing pump seal technology or pumps that can be applied to the areas identified as having poorer than average performance, except as provided in paragraph (d)(6)(v) of this section. The trial program shall be used to evaluate the feasibility of using in the process unit (or plant site) the pump designs or seal technologies, and operating and maintenance practices that have been identified by others as having low emission performance.

(i) The trial program shall include on-line trials of pump seal technologies or pump designs and operating and maintenance practices that have been identified in the available literature or in analysis by others as having the ability to perform with leak rates below 10 percent in similar services, as having low probability of failure, or as having no external actuating mechanism in contact with the process fluid. If any of the candidate superior performing pump seal technologies or pumps is not included in the performance trials, the reasons for rejecting specific technologies from consideration shall be documented as required in §63.181(h)(5)(ii).

(ii) The number of pump seal technologies or pumps in the trial evaluation program shall be the lesser of 1 percent or two pumps for programs involving single process units and the lesser of 1 percent or five pumps for programs involving a plant site or groups of process units. The minimum number of pumps or pump seal technologies in a trial program shall be one.

(iii) The trial evaluation program shall specify and include documentation of:

(A) The candidate superior performing pump seal designs or technologies to be evaluated, the stages for evaluating the identified candidate pump designs or pump seal technologies, including the time period necessary to test the applicability;

(B) The frequency of monitoring or inspection of the equipment;

(C) The range of operating conditions over which the component will be evaluated; and

(D) Conclusions regarding the emission performance and the appropriate operating conditions and services for the trial pump seal technologies or pumps.

(iv) The performance trials shall initially be conducted, at least, for a 6-month period beginning not later than 18 months after the start of the quality improvement program. No later than 24 months after the start of the quality improvement program, the owner or operator shall have identified pump seal technologies or pump designs that, combined with appropriate process, operating, and maintenance practices, operate with low emission performance for specific applications in the process unit. The owner or operator shall continue to conduct performance trials as long as no superior performing design or technology has been identified, except as provided in paragraph (d)(6)(vi) of this section. The initial list of superior emission performance pump designs or pump seal technologies shall be amended in the future, as appropriate, as additional information and experience is obtained.

(v) Any plant site with fewer than 400 valves and owned by a corporation with fewer than 100 employees shall be exempt from trial evaluations of pump seals or pump designs. Plant sites exempt from the trial evaluations of pumps shall begin the pump seal or pump replacement program at the start of the fourth year of the quality improvement program.

(vi) An owner or operator who has conducted performance trials on all alternative superior emission performance technologies suitable for the required applications in the process unit may stop conducting performance trials provided that a superior performing design or technology has been demonstrated or there are no technically feasible alternative superior technologies remaining. The owner or operator shall prepare an engineering evaluation documenting the physical, chemical, or engineering basis for the judgment that the superior emission performance technology is technically infeasible or demonstrating that it would not reduce emissions.

(7) Each owner or operator shall prepare and implement a pump quality assurance program that details purchasing specifications and maintenance procedures for all pumps and pump seals in the process unit. The quality assurance program may establish any number of categories, or classes, of pumps as needed to distinguish among operating conditions and services associated with poorer than average emission performance as well as those associated with better than average emission performance. The quality assurance program shall be developed considering the findings of the data analysis required under paragraph (d)(5) of this section, if applicable, the findings of the trial evaluation required in paragraph (d)(6) of this section, and the operating conditions in the process unit. The quality assurance program shall be updated each year as long as the process unit has the greater of either 10 percent or more leaking pumps or has three leaking pumps.

(i) The quality assurance program shall:

(A) Establish minimum design standards for each category of pumps or pump seal technology. The design standards shall specify known critical parameters such as tolerance, manufacturer, materials of construction, previous usage, or other applicable identified critical parameters;

(B) Require that all equipment orders specify the design standard (or minimum tolerances) for the pump or the pump seal;

(C) Provide for an audit procedure for quality control of purchased equipment to ensure conformance with purchase specifications. The audit program may be conducted by the owner or operator of the plant site or process unit or by a designated representative; and

(D) Detail off-line pump maintenance and repair procedures. These procedures shall include provisions to ensure that rebuilt or refurbished pumps and pump seals will meet the design specifications for the pump category and will operate such that emissions are minimized.

(ii) The quality assurance program shall be established no later than the start of the third year of the quality improvement program for plant sites with 400 or more valves or 100 or more employees; and no later than the start of the fourth year of the quality improvement program for plant sites with less than 400 valves and less than 100 employees.

(8) Beginning at the start of the third year of the quality improvement program for plant sites with 400 or more valves or 100 or more employees and at the start of the fourth year of the quality improvement program for plant sites with less than 400 valves and less than 100 employees, the owner or operator shall replace, as described in paragraphs (d)(8)(i) and (d)(8)(ii) of this section, the pumps or pump seals that are not superior emission performance technology with pumps or pump seals that have been identified as superior emission performance technology and that comply with the quality assurance standards for the pump category. Superior emission performance technology is that category or design of pumps or pump seals with emission performance which, when combined with appropriate process, operating, and maintenance practices, will result in less than 10 percent leaking pumps for specific applications in the process unit or plant site. Superior emission performance technology includes material or design changes to the existing pump, pump seal, seal support system, installation of multiple mechanical seals or equivalent, or pump replacement.

(i) Pumps or pump seals shall be replaced at the rate of 20 percent per year based on the total number of pumps in light liquid service. The calculated value shall be rounded to the nearest nonzero integer value. The minimum number of pumps or pump seals shall be one. Pump replacement shall continue until all pumps subject to the requirements of §63.163 of this subpart are pumps determined to be superior performance technology.

(ii) The owner or operator may delay replacement of pump seals or pumps with superior technology until the next planned process unit shutdown, provided the number of pump seals and pumps replaced is equivalent to the 20 percent or greater annual replacement rate.

(iii) The pumps shall be maintained as specified in the quality assurance program.

§ 63.177 Alternative means of emission limitation: General.

(a) Permission to use an alternative means of emission limitation under section 112(h)(3) of the Act shall be governed by the following procedures in paragraphs (b) through (e) of this section.

(b) Where the standard is an equipment, design, or operational requirement:

(1) Each owner or operator applying for permission to use an alternative means of emission limitation under §63.6(g) of subpart A of this part shall be responsible for collecting and verifying emission performance test data for an alternative means of emission limitation.

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Where the standard is a work practice:

(1) Each owner or operator applying for permission shall be responsible for collecting and verifying test data for an alternative means of emission limitation.

(2) For each kind of equipment for which permission is requested, the emission reduction achieved by the required work practices shall be demonstrated for a minimum period of 12 months.

(3) For each kind of equipment for which permission is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for permission shall commit, in writing, for each kind of equipment to work practices that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practices.

(5) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same or greater emission reduction as the required work practices of this subpart.

(d) An owner or operator may offer a unique approach to demonstrate the alternative means of emission limitation.

(e)(1) Manufacturers of equipment used to control equipment leaks of an organic HAP may apply to the Administrator for permission for an alternative means of emission limitation that achieves a reduction in emissions of the organic HAP achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will grant permission according to the provisions of paragraphs (b), (c), and (d) of this section.

§ 63.178   Alternative means of emission limitation: Batch processes.

(a) As an alternative to complying with the requirements of §§63.163 through 63.171 and §§63.173 through 63.176, an owner or operator of a batch process that operates in organic HAP service during the calendar year may comply with one of the standards specified in paragraphs (b) and (c) of this section, or the owner or operator may petition for approval of an alternative standard under the provisions of §63.177 of this subpart. The alternative standards of this section provide the options of pressure testing or monitoring the equipment for leaks. The owner or operator may switch among the alternatives provided the change is documented as specified in §63.181.

(b) The following requirements shall be met if an owner or operator elects to use pressure testing of batch product-process equipment to demonstrate compliance with this subpart. An owner or operator who complies with the provisions of this paragraph is exempt from the monitoring provisions of §63.163, §§63.168 and 63.169, and §§63.173 through 63.176 of this subpart.

(1) Each time equipment is reconfigured for production of a different product or intermediate, the batch product-process equipment train shall be pressure-tested for leaks before organic HAP is first fed to the equipment and the equipment is placed in organic HAP service.

(i) When the batch product-process train is reconfigured to produce a different product, pressure testing is required only for the new or disturbed equipment.

(ii) Each batch product process that operates in organic HAP service during a calendar year shall be pressure tested at least once during that calendar year.

(iii) Pressure testing is not required for routine seal breaks, such as changing hoses or filters, which are not part of the reconfiguration to produce a different product or intermediate.

(2) The batch product process equipment shall be tested either using the procedures specified in §63.180(f) of this subpart for pressure or vacuum loss or with a liquid using the procedures specified in §63.180(g) of this subpart.

(3)(i) For pressure or vacuum tests, a leak is detected if the rate of change in pressure is greater than 6.9 kilopascals (1 psig) in 1 hour or if there is visible, audible, or olfactory evidence of fluid loss.

(ii) For pressure tests using a liquid, a leak is detected if there are indications of liquids dripping or if there is other evidence of fluid loss.

(4)(i) If a leak is detected, it shall be repaired and the batch product-process equipment shall be retested before start-up of the process.

(ii) If a batch product-process fails the retest or the second of two consecutive pressure tests, it shall be repaired as soon as practicable, but not later than 30 calendar days after the second pressure test, provided the conditions specified in paragraph (d) of this section are met.

(c) The following requirements shall be met if an owner or operator elects to monitor the equipment to detect leaks by the method specified in §63.180(b) of this subpart to demonstrate compliance with this subpart.

(1) The owner or operator shall comply with the requirements of §§63.163 through 63.170, and §§63.172 through 63.176 of this subpart.

(2) The equipment shall be monitored for leaks by the method specified in §63.180(b) of this subpart when the equipment is in organic HAP service, in use with an acceptable surrogate volatile organic compound which is not an organic HAP, or is in use with any other detectable gas or vapor.

(3) The equipment shall be monitored for leaks as specified below:

(i) Each time the equipment is reconfigured for the production of a new product, the reconfigured equipment shall be monitored for leaks within 30 days of start-up of the process. This initial monitoring of reconfigured equipment shall not be included in determining percent leaking equipment in the process unit.

(ii) Connectors shall be monitored in accordance with the requirements in §63.174 of this subpart.

(iii) Equipment other than connectors shall be monitored at the frequencies specified in table 1 of this subpart. The operating time shall be determined as the proportion of the year the batch product-process that is subject to the provisions of this subpart is operating.

(iv) The monitoring frequencies specified in table 1 of this subpart are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor anytime during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. For example, if the equipment is not operating during the scheduled monitoring period, the monitoring can be done during the next period when the process is operating.

(4) If a leak is detected, it shall be repaired as soon as practicable but not later than 15 calendar days after it is detected, except as provided in paragraph (d) of this section.

(d) Delay of repair of equipment for which leaks have been detected is allowed if the replacement equipment is not available providing the following conditions are met:

(1) Equipment supplies have been depleted and supplies had been sufficiently stocked before the supplies were depleted.

(2) The repair is made no later than 10 calendar days after delivery of the replacement equipment.

§ 63.179 Alternative means of emission limitation: Enclosed-vented process units.

Process units enclosed in such a manner that all emissions from equipment leaks are vented through a closed-vent system to a control device meeting the requirements of §63.172 of this subpart are exempt from the requirements of §63.163, through 63.171, and §§63.173 and 63.174 of this subpart. The enclosure shall be maintained under a negative pressure at all times while the process unit is in operation to ensure that all emissions are routed to a control device.

§ 63.180 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test methods and procedures requirements provided in this section.

(b) Monitoring, as required under this subpart, shall comply with the following requirements:

(1) Monitoring shall comply with Method 21 of 40 CFR part 60, appendix A.

(2)(i) Except as provided for in paragraph (b)(2)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in Section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual VOC in the stream. For process streams that contain nitrogen, water, air, or other inerts which are not organic HAP's or VOC's, the average stream response factor may be calculated on an inert-free basis. The response factor may be determined at any concentration for which monitoring for leaks will be conducted.

(ii) If no instrument is available at the plant site that will meet the performance criteria specified in paragraph (b)(2)(i) of this section, the instrument readings may be adjusted by multiplying by the average response factor of the process fluid, calculated on an inert-free basis as described in paragraph (b)(2)(i) of this section.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21 of 40 CFR part 60, appendix A.

(4) Calibration gases shall be:

(i) Zero air (less than 10 parts per million of hydrocarbon in air); and

(ii) Mixtures of methane in air at the concentrations specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(C) of this section. A calibration gas other than methane in air may be used if the instrument does not respond to methane or if the instrument does not meet the performance criteria specified in paragraph (b)(2)(i) of this section. In such cases, the calibration gas may be a mixture of one or more of the compounds to be measured in air.

(A) For Phase I, a mixture of methane or other compounds, as applicable, in air at a concentration of approximately, but less than, 10,000 parts per million.

(B) For Phase II, a mixture of methane or other compounds, as applicable, and air at a concentration of approximately, but less than, 10,000 parts per million for agitators, 5,000 parts per million for pumps, and 500 parts per million for all other equipment, except as provided in paragraph (b)(4)(iii) of this section.

(C) For Phase III, a mixture of methane or other compounds, as applicable, and air at a concentration of approximately, but less than, 10,000 parts per million methane for agitators; 2,000 parts per million for pumps in food/medical service; 5,000 parts per million for pumps in polymerizing monomer service; 1,000 parts per million for all other pumps; and 500 parts per million for all other equipment, except as provided in paragraph (b)(4)(iii) of this section.

(iii) The instrument may be calibrated at a higher methane concentration than the concentration specified for that piece of equipment. The concentration of the calibration gas may exceed the concentration specified as a leak by no more than 2,000 parts per million. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 parts per million above the concentration specified as a leak and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 parts per million. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(5) Monitoring shall be performed when the equipment is in organic HAP service, in use with an acceptable surrogate volatile organic compound which is not an organic HAP, or is in use with any other detectable gas or vapor.

(6) Monitoring data that do not meet the criteria specified in paragraphs (b)(1) through (b)(5) of this section may be used to qualify for less frequent monitoring under the provisions in §63.168(d)(2) and (d)(3) or §63.174(b)(3)(ii) or (b)(3)(iii) of this subpart provided the data meet the conditions specified in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

(i) The data were obtained before April 22, 1994.

(ii) The departures from the criteria specified in paragraphs (b)(1) through (b)(5) of this section or from the specified monitoring frequency of §63.168(c) are minor and do not significantly affect the quality of the data. Examples of minor departures are monitoring at a slightly different frequency (such as every six weeks instead of monthly or quarterly), following the performance criteria of section 3.1.2(a) of Method 21 of appendix A of 40 CFR part 60 instead of paragraph (b)(2) of this section, or monitoring at a different leak definition if the data would indicate the presence or absence of a leak at the concentration specified in this subpart. Failure to use a calibrated instrument is not considered a minor departure.

(c) When equipment is monitored for compliance as required in §§63.164(i), 63.165(a), and 63.172(f) or when equipment subject to a leak definition of 500 ppm is monitored for leaks as required by this subpart, the owner or operator may elect to adjust or not to adjust the instrument readings for background. If an owner or operator elects to not adjust instrument readings for background, the owner or operator shall monitor the equipment according to the procedures specified in paragraphs (b)(1) through (b)(4) of this section. In such case, all instrument readings shall be compared directly to the applicable leak definition to determine whether there is a leak. If an owner or operator elects to adjust instrument readings for background, the owner or operator shall monitor the equipment according to the procedures specified in paragraphs (c)(1) through (c)(4) of this section.

(1) The requirements of paragraphs (b) (1) through (4) of this section shall apply.

(2) The background level shall be determined, using the same procedures that will be used to determine whether the equipment is leaking.

(3) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Method 21 of 40 CFR part 60, appendix A.

(4) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 parts per million for determining compliance.

(d)(1) Each piece of equipment within a process unit that can reasonably be expected to contain equipment in organic HAP service is presumed to be in organic HAP service unless an owner or operator demonstrates that the piece of equipment is not in organic HAP service. For a piece of equipment to be considered not in organic HAP service, it must be determined that the percent organic HAP content can be reasonably expected not to exceed 5 percent by weight on an annual average basis. For purposes of determining the percent organic HAP content of the process fluid that is contained in or contacts equipment, Method 18 of 40 CFR part 60, appendix A shall be used.

(2)(i) An owner or operator may use good engineering judgment rather than the procedures in paragraph (d)(1) of this section to determine that the percent organic HAP content does not exceed 5 percent by weight. When an owner or operator and the Administrator do not agree on whether a piece of equipment is not in organic HAP service, however, the procedures in paragraph (d)(1) of this section shall be used to resolve the disagreement.

(ii) Conversely, the owner or operator may determine that the organic HAP content of the process fluid does not exceed 5 percent by weight by, for example, accounting for 98 percent of the content and showing that organic HAP is less than 3 percent.

(3) If an owner or operator determines that a piece of equipment is in organic HAP service, the determination can be revised after following the procedures in paragraph (d)(1) of this section, or by documenting that a change in the process or raw materials no longer causes the equipment to be in organic HAP service.

(4) Samples used in determining the percent organic HAP content shall be representative of the process fluid that is contained in or contacts the equipment.

(e) When a flare is used to comply with §63.172(d), the owner or operator shall comply with paragraphs (e)(1) through (3) of this section. The owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration.

(1) Conduct a visible emission test using the techniques specified in §63.11(b)(4).

(2) Determine the net heating value of the gas being combusted using the techniques specified in §63.11(b)(6).

(3) Determine the exit velocity using the techniques specified in either §63.11(b)(7)(i) (and §63.11(b)(7)(iii), where applicable) or §63.11(b)(8), as appropriate.

(f) The following procedures shall be used to pressure test batch product-process equipment for pressure or vacuum loss to demonstrate compliance with the requirements of §63.178(b)(3)(i) of this subpart.

(1) The batch product-process equipment train shall be pressurized with a gas to a pressure less than the set pressure of any safety relief devices or valves or to a pressure slightly above the operating pressure of the equipment, or alternatively, the equipment shall be placed under a vacuum.

(2) Once the test pressure is obtained, the gas source or vacuum source shall be shut off.

(3) The test shall continue for not less than 15 minutes unless it can be determined in a shorter period of time that the allowable rate of pressure drop or of pressure rise was exceeded. The pressure in the batch product-process equipment shall be measured after the gas or vacuum source is shut off and at the end of the test period. The rate of change in pressure in the batch product-process equipment shall be calculated using the following equation:

$$\Delta\frac{P}{t}=\frac{\left(\left|P_f-P_i\right|\right)}{\left(t_f-t_i\right)}$$

where:

$\Delta P/t$=Change in pressure, psig/hr.

P_f=Final pressure, psig.

P_i=Initial pressure, psig.

t_f-t_i=Elapsed time, hours.

(4) The pressure shall be measured using a pressure measurement device (gauge, manometer, or equivalent) which has a precision of ±2.5 millimeter mercury in the range of test pressure and is capable of measuring pressures up to the relief set pressure of the pressure relief device. If such a pressure measurement device is not reasonably available, the owner or operator shall use a pressure measurement device with a precision of at least +10 percent of the test pressure of the equipment and shall extend the duration of the test for the time necessary to detect a pressure loss or rise that equals a rate of one psig per hour.

(5) An alternative procedure may be used for leak testing the equipment if the owner or operator demonstrates the alternative procedure is capable of detecting a pressure loss or rise.

(g) The following procedures shall be used to pressure-test batch product-process equipment using a liquid to demonstrate compliance with the requirements of §63.178(b)(3)(ii) of this subpart.

(1) The batch product-process equipment train, or section of the train, shall be filled with the test liquid (e.g., water, alcohol) until normal operating pressure is obtained. Once the equipment is filled, the liquid source shall be shut off.

(2) The test shall be conducted for a period of at least 60 minutes, unless it can be determined in a shorter period of time that the test is a failure.

(3) Each seal in the equipment being tested shall be inspected for indications of liquid dripping or other indications of fluid loss. If there are any indications of liquids dripping or of fluid loss, a leak is detected.

(4) An alternative procedure may be used for leak testing the equipment, if the owner or operator demonstrates the alternative procedure is capable of detecting losses of fluid.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 61 FR 31440, June 20, 1996; 62 FR 2792, Jan. 17, 1997; 66 FR 6936, Jan. 22, 2001]

§ 63.181 Recordkeeping requirements.

(a) An owner or operator of more than one process unit subject to the provisions of this subpart may comply with the recordkeeping requirements for these process units in one recordkeeping system if the system identifies each record by process unit and the program being implemented (e.g., quarterly monitoring, quality improvement) for each type of equipment. All records and information required by this section shall be maintained in a manner that can be readily accessed at the plant site. This could include physically locating the records at the plant site or accessing the records from a central location by computer at the plant site.

(b) Except as provided in paragraph (e) of this section, the following information pertaining to all equipment in each process unit subject to the requirements in §§63.162 through 63.174 of this subpart shall be recorded:

(1)(i) A list of identification numbers for equipment (except connectors exempt from monitoring and recordkeeping identified in §63.174 of this subpart and instrumentation systems) subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated. With respect to connectors, the list shall be complete no later than the completion of the initial survey required by §63.174 (b)(1) or (b)(2) of this subpart.

(ii) A schedule by process unit for monitoring connectors subject to the provisions of §63.174(a) of this subpart and valves subject to the provisions of §63.168(d) of this subpart.

(iii) Physical tagging of the equipment to indicate that it is in organic HAP service is not required. Equipment subject to the provisions of this subpart may be identified on a plant site plan, in log entries, or by other appropriate methods.

(2)(i) A list of identification numbers for equipment that the owner or operator elects to equip with a closed-vent system and control device, under the provisions of §63.163(g), §63.164(h), §63.165(c), or §63.173(f) of this subpart.

(ii) A list of identification numbers for compressors that the owner or operator elects to designate as operating with an instrument reading of less than 500 parts per million above background, under the provisions of §63.164(i) of this subpart.

(iii) Identification of surge control vessels or bottoms receivers subject to the provisions of this subpart that the owner or operator elects to equip with a closed-vent system and control device, under the provisions of §63.170 of this subpart.

(3)(i) A list of identification numbers for pressure relief devices subject to the provisions in §63.165(a) of this subpart.

(ii) A list of identification numbers for pressure relief devices equipped with rupture disks, under the provisions of §63.165(d) of this subpart.

(4) Identification of instrumentation systems subject to the provisions of this subpart. Individual components in an instrumentation system need not be identified.

(5) Identification of screwed connectors subject to the requirements of §63.174(c)(2) of this subpart. Identification can be by area or grouping as long as the total number within each group or area is recorded.

(6) The following information shall be recorded for each dual mechanical seal system:

(i) Design criteria required in §§63.163(e)(6)(i), 63.164(e)(2), and 63.173(d)(6)(i) of this subpart and an explanation of the design criteria; and

(ii) Any changes to these criteria and the reasons for the changes.

(7) The following information pertaining to all pumps subject to the provisions of §63.163(j), valves subject to the provisions of §63.168(h) and (i) of this subpart, agitators subject to the provisions of §63.173(h) through (j), and connectors subject to the provisions of §63.174(f) and (g) of this subpart shall be recorded:

(i) Identification of equipment designated as unsafe to monitor, difficult to monitor, or unsafe to inspect and the plan for monitoring or inspecting this equipment.

(ii) A list of identification numbers for the equipment that is designated as difficult to monitor, an explanation of why the equipment is difficult to monitor, and the planned schedule for monitoring this equipment.

(iii) A list of identification numbers for connectors that are designated as unsafe to repair and an explanation why the connector is unsafe to repair.

(8)(i) A list of valves removed from and added to the process unit, as described in §63.168(e)(1) of this subpart, if the net credits for removed valves is expected to be used.

(ii) A list of connectors removed from and added to the process unit, as described in §63.174(i)(1) of this subpart, and documentation of the integrity of the weld for any removed connectors, as required in §63.174(j) of this subpart. This is not required unless the net credits for removed connectors is expected to be used.

(9)(i) For batch process units that the owner or operator elects to monitor as provided under §63.178(c) of this subpart, a list of equipment added to batch product process units since the last monitoring period required in §63.178(c)(3)(ii) and (3)(iii) of this subpart.

(ii) Records demonstrating the proportion of the time during the calendar year the equipment is in use in a batch process that is subject to the provisions of this subpart. Examples of suitable documentation are records of time in use for individual pieces of equipment or average time in use for the process unit. These records are not required if the owner or operator does not adjust monitoring frequency by the time in use, as provided in §63.178(c)(3)(iii) of this subpart.

(10) For any leaks detected as specified in §§63.163 and 63.164; §§63.168 and 63.169; and §§63.172 through 63.174 of this subpart, a weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(c) For visual inspections of equipment subject to the provisions of this subpart (e.g., §63.163(b)(3), §63.163(e)(4)(i)), the owner or operator shall document that the inspection was conducted and the date of the inspection. The owner or operator shall maintain records as specified in paragraph (d) of this section for leaking equipment identified in this inspection, except as provided in paragraph (e) of this section. These records shall be retained for 2 years.

(d) When each leak is detected as specified in §§63.163 and 63.164; §§63.168 and 63.169; and §§63.172 through 63.174 of this subpart, the following information shall be recorded and kept for 2 years:

(1) The instrument and the equipment identification number and the operator name, initials, or identification number.

(2) The date the leak was detected and the date of first attempt to repair the leak.

(3) The date of successful repair of the leak.

(4) Maximum instrument reading measured by Method 21 of 40 CFR part 60, appendix A after it is successfully repaired or determined to be nonrepairable.

(5) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(i) The owner or operator may develop a written procedure that identifies the conditions that justify a delay of repair. The written procedures may be included as part of the startup/shutdown/malfunction plan, required by §63.6(e)(3), for the source or may be part of a separate document that is maintained at the plant site. In such cases, reasons for delay of repair may be documented by citing the relevant sections of the written procedure.

(ii) If delay of repair was caused by depletion of stocked parts, there must be documentation that the spare parts were sufficiently stocked on-site before depletion and the reason for depletion.

(6) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(7)(i) Identification, either by list, location (area or grouping), or tagging of connectors that have been opened or otherwise had the seal broken since the last monitoring period required in §63.174(b) of this subpart, as described in §63.174(c)(1) of this subpart, unless the owner or operator elects to comply with the provisions of §63.174(c)(1)(ii) of this subpart.

(ii) The date and results of monitoring as required in §63.174(c) of this subpart. If identification of connectors that have been opened or otherwise had the seal broken is made by location under paragraph (d)(7)(i) of this section, then all connectors within the designated location shall be monitored.

(8) The date and results of the monitoring required in §63.178(c)(3)(i) of this subpart for equipment added to a batch process unit since the last monitoring period required in §63.178 (c)(3)(ii) and (c)(3)(iii) of this subpart. If no leaking equipment is found in this monitoring, the owner or operator shall record that the inspection was performed. Records of the actual monitoring results are not required.

(9) Copies of the periodic reports as specified in §63.182(d) of this subpart, if records are not maintained on a computerized database capable of generating summary reports from the records.

(e) The owner or operator of a batch product process who elects to pressure test the batch product process equipment train to demonstrate compliance with this subpart is exempt from the requirements of paragraphs (b), (c), (d), and (f) of this section. Instead, the owner or operator shall maintain records of the following information:

(1) The identification of each product, or product code, produced during the calendar year. It is not necessary to identify individual items of equipment in a batch product process equipment train.

(2) [Reserved]

(3) Physical tagging of the equipment to identify that it is in organic HAP service and subject to the provisions of this subpart is not required. Equipment in a batch product process subject to the provisions of this subpart may be identified on a plant site plan, in log entries, or by other appropriate methods.

(4) The dates of each pressure test required in §63.178(b) of this subpart, the test pressure, and the pressure drop observed during the test.

(5) Records of any visible, audible, or olfactory evidence of fluid loss.

(6) When a batch product process equipment train does not pass two consecutive pressure tests, the following information shall be recorded in a log and kept for 2 years:

(i) The date of each pressure test and the date of each leak repair attempt.

(ii) Repair methods applied in each attempt to repair the leak.

(iii) The reason for the delay of repair.

(iv) The expected date for delivery of the replacement equipment and the actual date of delivery of the replacement equipment.

(v) The date of successful repair.

(f) The dates and results of each compliance test required for compressors subject to the provisions in §63.164(i) and the dates and results of the monitoring following a pressure release for each pressure relief device subject to the provisions in §§63.165 (a) and (b) of this subpart. The results shall include:

(1) The background level measured during each compliance test.

(2) The maximum instrument reading measured at each piece of equipment during each compliance test.

(g) The owner or operator shall maintain records of the information specified in paragraphs (g)(1) through (g)(3) of this section for closed-vent systems and control devices subject to the provisions of §63.172 of this subpart. The records specified in paragraph (g)(1) of this section shall be retained for the life of the equipment. The records specified in paragraphs (g)(2) and (g)(3) of this section shall be retained for 2 years.

(1) The design specifications and performance demonstrations specified in paragraphs (g)(1)(i) through (g)(1)(iv) of this section.

(i) Detailed schematics, design specifications of the control device, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) The flare design (i.e., steam-assisted, air-assisted, or non-assisted) and the results of the compliance demonstration required by §63.11(b) of subpart A of this part.

(iv) A description of the parameter or parameters monitored, as required in §63.172(e) of this subpart, to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(2) Records of operation of closed-vent systems and control devices, as specified in paragraphs (g)(2)(i) through (g)(2)(iii) of this section.

(i) Dates and durations when the closed-vent systems and control devices required in §§63.163 through 63.166, and §63.170 of this subpart are not operated as designed as indicated by the monitored parameters, including periods when a flare pilot light system does not have a flame.

(ii) Dates and durations during which the monitoring system or monitoring device is inoperative.

(iii) Dates and durations of start-ups and shutdowns of control devices required in §§63.163 through 63.166, and §63.170 of this subpart.

(3) Records of inspections of closed-vent systems subject to the provisions of §63.172 of this subpart, as specified in paragraphs (g)(3)(i) and (g)(3)(ii) of this section.

(i) For each inspection conducted in accordance with the provisions of §63.172(f)(1) or (f)(2) of this subpart during which no leaks were detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(ii) For each inspection conducted in accordance with the provisions of §63.172(f)(1) or (f)(2) of this subpart during which leaks were detected, the information specified in paragraph (d) of this section shall be recorded.

(h) Each owner or operator of a process unit subject to the requirements of §§63.175 and 63.176 of this subpart shall maintain the records specified in paragraphs (h)(1) through (h)(9) of this section for the period of the quality improvement program for the process unit.

(1) For owners or operators who elect to use a reasonable further progress quality improvement program, as specified in §63.175(d) of this subpart:

(i) All data required in §63.175(d)(2) of this subpart.

(ii) The percent leaking valves observed each quarter and the rolling average percent reduction observed in each quarter.

(iii) The beginning and ending dates while meeting the requirements of §63.175(d) of this subpart.

(2) For owners or operators who elect to use a quality improvement program of technology review and improvement, as specified in §63.175(e) of this subpart:

(i) All data required in §63.175(e)(2) of this subpart.

(ii) The percent leaking valves observed each quarter.

(iii) Documentation of all inspections conducted under the requirements of §63.175(e)(4) of this subpart, and any recommendations for design or specification changes to reduce leak frequency.

(iv) The beginning and ending dates while meeting the requirements of §63.175(e) of this subpart.

(3) For owners or operators subject to the requirements of the pump quality improvement program as specified in §63.176 of this subpart:

(i) All data required in §63.176(d)(2) of this subpart.

(ii) The rolling average percent leaking pumps.

(iii) Documentation of all inspections conducted under the requirements of §63.176(d)(4) of this subpart, and any recommendations for design or specification changes to reduce leak frequency.

(iv) The beginning and ending dates while meeting the requirements of §63.176(d) of this subpart.

(4) If a leak is not repaired within 15 calendar days after discovery of the leak, the reason for the delay and the expected date of successful repair.

(5) Records of all analyses required in §§63.175(e) and 63.176(d) of this subpart. The records will include the following:

(i) A list identifying areas associated with poorer than average performance and the associated service characteristics of the stream, the operating conditions and maintenance practices.

(ii) The reasons for rejecting specific candidate superior emission performing valve or pump technology from performance trials.

(iii) The list of candidate superior emission performing valve or pump technologies, and documentation of the performance trial program items required under §§63.175(e)(6)(iii) and 63.176(d)(6)(iii) of this subpart.

(iv) The beginning date and duration of performance trials of each candidate superior emission performing technology.

(6) All records documenting the quality assurance program for valves or pumps as specified in §§63.175(e)(7) and 63.176(d)(7) of this subpart.

(7) Records indicating that all valves or pumps replaced or modified during the period of the quality improvement program are in compliance with the quality assurance requirements in §63.175(e)(7) and §63.176(d)(7) of this subpart.

(8) Records documenting compliance with the 20 percent or greater annual replacement rate for pumps as specified in §63.176(d)(8) of this subpart.

(9) Information and data to show the corporation has fewer than 100 employees, including employees providing professional and technical contracted services.

(i) The owner or operator of equipment in heavy liquid service shall comply with the requirements of either paragraph (i)(1) or (i)(2) of this section, as provided in paragraph (i)(3) of this section.

(1) Retain information, data, and analyses used to determine that a piece of equipment is in heavy liquid service.

(2) When requested by the Administrator, demonstrate that the piece of equipment or process is in heavy liquid service.

(3) A determination or demonstration that a piece of equipment or process is in heavy liquid service shall include an analysis or demonstration that the process fluids do not meet the definition of “in light liquid service.” Examples of information that could document this include, but are not limited to, records of chemicals purchased for the process, analyses of process stream composition, engineering calculations, or process knowledge.

(j) Identification, either by list, location (area or group) of equipment in organic HAP service less than 300 hours per year within a process unit subject to the provisions of this subpart under §63.160 of this subpart.

(k) Owners and operators choosing to comply with the requirements of §63.179 of this subpart shall maintain the following records:

(1) Identification of the process unit(s) and the organic HAP's they handle.

(2) A schematic of the process unit, enclosure, and closed-vent system.

(3) A description of the system used to create a negative pressure in the enclosure to ensure that all emissions are routed to the control device.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48177, Sept. 20, 1994; 60 FR 18030, Apr. 10, 1995; 61 FR 31441, June 20, 1996; 62 FR 2792, Jan. 17, 1997; 64 FR 20198, Apr. 26, 1999; 68 FR 37344, June 23, 2003]

§ 63.182   Reporting requirements.

(a) Each owner or operator of a source subject to this subpart shall submit the reports listed in paragraphs (a)(1) through (a)(5) of this section. Owners or operators requesting an extension of compliance shall also submit the report listed in paragraph (a)(6) of this section.

(1) An Initial Notification described in paragraph (b) of this section, and

(2) A Notification of Compliance Status described in paragraph (c) of this section,

(3) Periodic Reports described in paragraph (d) of this section, and

(4)–(5) [Reserved]

(6) Pursuant to section 112(i)(3)(B) of the Act, an owner or operator may request an extension allowing an existing source up to 1 additional year beyond the compliance date specified in the subpart that references this subpart.

(i) For purposes of this subpart, a request for an extension shall be submitted to the operating permit authority as part of the operating permit application. If the State in which the source is located does not have an approved operating permit program, a request for an extension shall be submitted to the Administrator as a separate submittal. The dates specified in §63.6(i) of subpart A of this part for submittal of requests for extensions shall not apply to sources subject to this subpart.

(ii) A request for an extension of compliance must include the data described in §63.6(i)(6)(i) (A), (B), and (D) of subpart A of this part.

(iii) The requirements in §63.6(i)(8) through (i)(14) of subpart A of this part will govern the review and approval of requests for extensions of compliance with this subpart.

(b) Each owner or operator of an existing or new source subject to the provisions of this subpart shall submit a written Initial Notification to the Administrator, containing the information described in paragraph (b)(1), according to the schedule in paragraph (b)(2) of this section. The Initial Notification provisions in §63.9(b)(1) through (b)(3) of subpart A of this part shall not apply to owners or operators of sources subject to this subpart.

(1) The Initial Notification shall include the following information:

(i) The name and address of the owner or operator;

(ii) The address (physical location) of the affected source;

(iii) An identification of the chemical manufacturing processes subject to this subpart; and

(iv) A statement of whether the source can achieve compliance by the applicable compliance date specified in the subpart in 40 CFR part 63 that references this subpart.

(2) The Initial Notification shall be submitted according to the schedule in paragraph (b)(2)(i), (b)(2)(ii), or (b)(2)(iii) of this section, as applicable.

(i) For an existing source, the Initial Notification shall be submitted within 120 days after the date of promulgation of the subpart that references this subpart.

(ii) For a new source that has an initial start-up 90 days after the date of promulgation of this subpart or later, the application for approval of construction or reconstruction required by §63.5(d) of subpart A of this part shall be submitted in lieu of the Initial Notification. The application shall be submitted as soon as practicable before the construction or reconstruction is planned to commence (but it need not be sooner than 90 days after the date of promulgation of the subpart that references this subpart).

(iii) For a new source that has an initial start-up prior to 90 days after the date of promulgation of the applicable subpart, the Initial Notification shall be submitted within 90 days after the date of promulgation of the subpart that references this subpart.

(c) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status within 90 days after the compliance dates specified in the subpart in 40 CFR part 63 that references this subpart, except as provided in paragraph (c)(4) of this section.

(1) The notification shall provide the information listed in paragraphs (c)(1)(i) through (c)(1)(iv) of this section for each process unit subject to the requirements of §63.163 through §63.174 of this subpart.

(i) Process unit identification.

(ii) Number of each equipment type (e.g., valves, pumps) excluding equipment in vacuum service.

(iii) Method of compliance with the standard (for example, “monthly leak detection and repair” or “equipped with dual mechanical seals”).

(iv) Planned schedule for each phase of the requirements in §63.163 and §63.168 of this subpart.

(2) The notification shall provide the information listed in paragraphs (c)(2)(i) and (c)(2)(ii) of this section for each process unit subject to the requirements of §63.178(b) of this subpart.

(i) Batch products or product codes subject to the provisions of this subpart, and

(ii) Planned schedule for pressure testing when equipment is configured for production of products subject to the provisions of this subpart.

(3) The notification shall provide the information listed in paragraphs (c)(3)(i) and (c)(3)(ii) of this section for each process unit subject to the requirements in §63.179 of this subpart.

(i) Process unit identification.

(ii) A description of the system used to create a negative pressure in the enclosure and the control device used to comply with the requirements of §63.172 of this subpart.

(4) For existing sources subject to subpart F of this part, the Notification of Compliance Status shall be submitted for the group of process units with the earliest compliance date specified in §63.100(k) of subpart F of this part, by no later than 90 days after the compliance date for that group. The Notification of Compliance Status for each subsequent group shall be submitted as part of the first periodic report that is due not less than 90 days after the compliance date for that group.

(d) The owner or operator of a source subject to this subpart shall submit Periodic Reports.

(1) A report containing the information in paragraphs (d)(2), (d)(3), and (d)(4) of this section shall be submitted semiannually starting 6 months after the Notification of Compliance Status, as required in paragraph (c) of this section. The first periodic report shall cover the first 6 months after the compliance date specified in §63.100(k)(3) of subpart F. Each subsequent periodic report shall cover the 6 month period following the preceding period.

(2) For each process unit complying with the provisions of §63.163 through §63.174 of this subpart, the summary information listed in paragraphs (i) through (xvi) of this paragraph for each monitoring period during the 6-month period.

(i) The number of valves for which leaks were detected as described in §63.168(b) of this subpart, the percent leakers, and the total number of valves monitored;

(ii) The number of valves for which leaks were not repaired as required in §63.168(f) of this subpart, identifying the number of those that are determined nonrepairable;

(iii) The number of pumps for which leaks were detected as described in §63.163(b) of this subpart, the percent leakers, and the total number of pumps monitored;

(iv) The number of pumps for which leaks were not repaired as required in §63.163(c) of this subpart;

(v) The number of compressors for which leaks were detected as described in §63.164(f) of this subpart;

(vi) The number of compressors for which leaks were not repaired as required in §63.164(g) of this subpart;

(vii) The number of agitators for which leaks were detected as described in §63.173(a) and (b) of this subpart;

(viii) The number of agitators for which leaks were not repaired as required in §63.173(c) of this subpart;

(ix) The number of connectors for which leaks were detected as described in §63.174(a) of this subpart, the percent of connectors leaking, and the total number of connectors monitored;

(x) [Reserved]

(xi) The number of connectors for which leaks were not repaired as required in §63.174(d) of this subpart, identifying the number of those that are determined nonrepairable;

(xii) [Reserved]

(xiii) The facts that explain any delay of repairs and, where appropriate, why a process unit shutdown was technically infeasible.

(xiv) The results of all monitoring to show compliance with §§63.164(i), 63.165(a), and 63.172(f) of this subpart conducted within the semiannual reporting period.

(xv) If applicable, the initiation of a monthly monitoring program under §63.168(d)(1)(i) of this subpart, or a quality improvement program under either §§63.175 or 63.176 of this subpart.

(xvi) If applicable, notification of a change in connector monitoring alternatives as described in §63.174(c)(1) of this subpart.

(xvii) If applicable, the compliance option that has been selected under §63.172(n).

(3) For owners or operators electing to meet the requirements of §63.178(b) of this subpart, the report shall include the information listed in paragraphs (i) through (v) of this paragraph for each process unit.

(i) Batch product process equipment train identification;

(ii) The number of pressure tests conducted;

(iii) The number of pressure tests where the equipment train failed the pressure test;

(iv) The facts that explain any delay of repairs; and

(v) The results of all monitoring to determine compliance with §63.172(f) of this subpart.

(4) The information listed in paragraph (c) of this section for the Notification of Compliance Status for process units with later compliance dates. Any revisions to items reported in earlier Notification of Compliance Status, if the method of compliance has changed since the last report.

[59 FR 19568, Apr. 22, 1994, as amended at 59 FR 48178, Sept. 20, 1994; 60 FR 18030, Apr. 10, 1995; 60 FR 63631, Dec. 12, 1995; 62 FR 2792, Jan. 17, 1997]

§ 63.183 Implementation and enforcement.

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as the applicable State, local, or Tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or Tribal agency, then that agency, in addition to the U.S. EPA, has the authority to implement and enforce this subpart. Contact the applicable U.S. EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to a State, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or Tribal agency under subpart E of this part, the authorities contained in paragraph (c) of this section are retained by the Administrator of U.S. EPA and cannot be transferred to the State, local, or Tribal agency.

(c) The authorities that cannot be delegated to State, local, or Tribal agencies are as specified in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the requirements in §§63.160, 63.162 through 63.176, 63.178 through 63.179. Follow the applicable procedures of §63.177 to request an alternative means of emission limitation for batch processes and enclosed-vented process units. Where these standards reference another subpart, the cited provisions will be delegated according to the delegation provisions of the referenced subpart. Where these standards reference another subpart and modify the requirements, the requirements shall be modified as described in this subpart. Delegation of the modified requirements will also occur according to the delegation provisions of the referenced subpart.

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f), as defined in §63.90, and as required in this subpart.

(3) Approval of major alternatives to monitoring under §63.8(f), as defined in §63.90, and as required in this subpart.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f), as defined in §63.90, and as required in this subpart.

[68 FR 37345, June 23, 2003]

Table 1 to Subpart H of Part 63—Batch Processes

Monitoring Frequency for Equipment Other than Connectors

Operating time (% of year)	**Equivalent continuous process monitoring frequency time in use**		
	Monthly	**Quarterly**	**Semiannually**
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three times	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

Table 2 to Subpart H of Part 63—Surge Control Vessels and Bottoms Receivers at Existing Sources

Vessel capacity (cubic meters)	Vapor pressure[1](kilopascals)
75 ≤ capacity < 151	≥13.1
151 ≤ capacity	≥ 5.2[a]

[1] Maximum true vapor pressure of total organic HAP at operating temperature as defined in subpart G of this part.

[60 FR 18025, Apr. 10, 1995]

Table 3 to Subpart H of Part 63—Surge Control Vessels and Bottoms Receivers at New Sources

Vessel capacity (cubic meters)	Vapor pressure[1](kilopascals)
38 ≤ capacity < 151	≥ 13.1
151 ≤ capacity	≥ 0.7

[1] Maximum true vapor pressure of total organic HAP at operating temperature as defined in subpart G of this part.

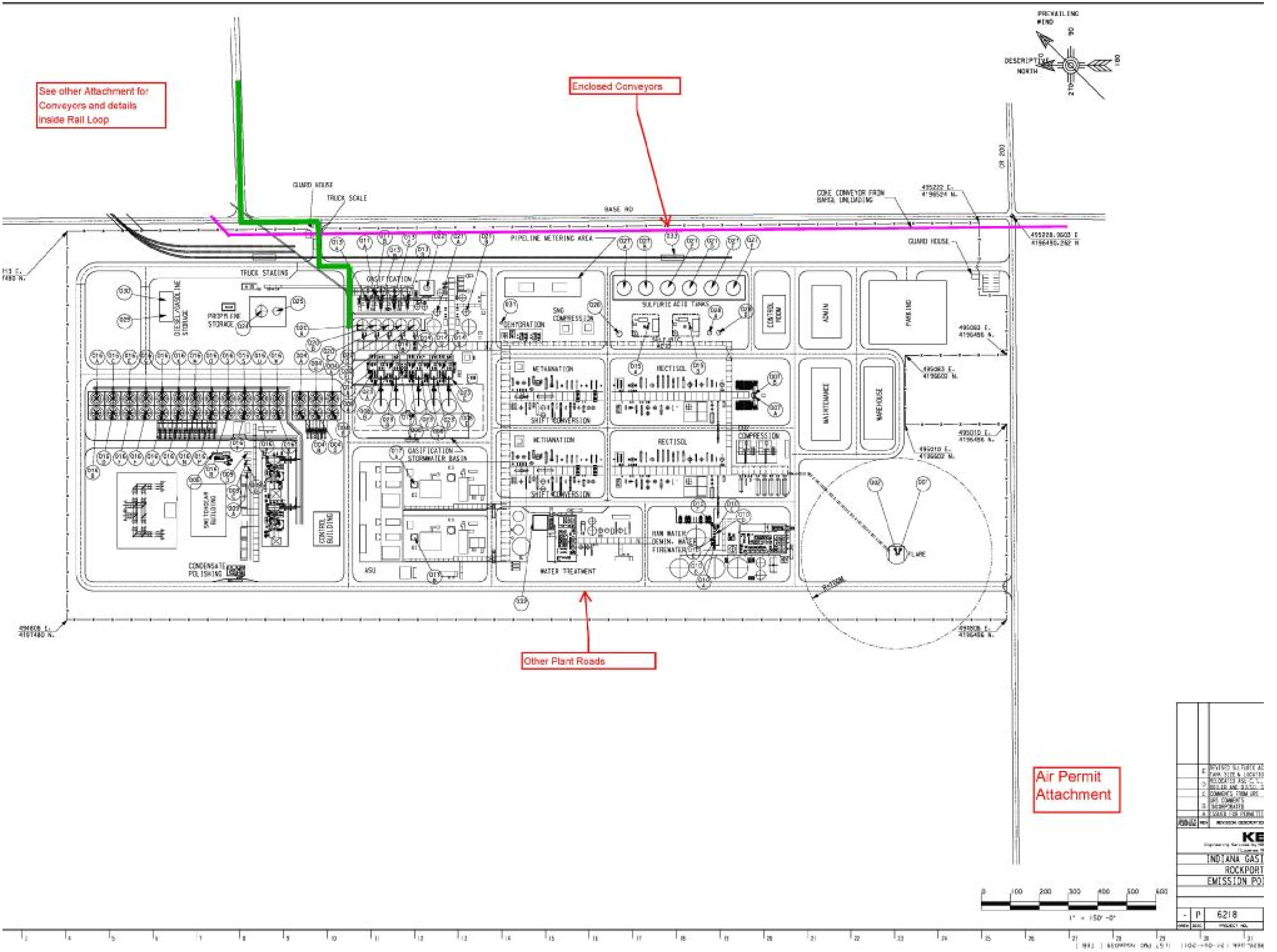
[60 FR 18025, Apr. 10, 1995]

Table 4 to Subpart H of Part 63—Applicable 40 CFR Part 63 General Provisions

40 CFR part 63, subpart A, provisions applicable to subpart H
§63.1(a)(1), (a)(2), (a)(3), (a)(13), (a)(14), (b)(2) and (c)(4)
§63.2
§63.5(a)(1), (a)(2), (b), (d)(1)(ii), (d)(4), (e), (f)(1) and (f)(2)
§63.6(a), (b)(3), (c)(5), (i)(1), (i)(2), (i)(4)(i)(A), (i)(5) through (i)(14), (i)(16) and (j)
§63.9(a)(2), (b)(4)(i)[a], (b)(4)(ii), (b)(4)(iii), (b)(5)a, (c) and (d)
§63.10(d)(4)
§63.11 (c), (d), and (e)
§63.12(b)

[a] The notifications specified in §63.9(b)(4)(i) and (b)(5) shall be submitted at the times specified in 40 CFR part 65.

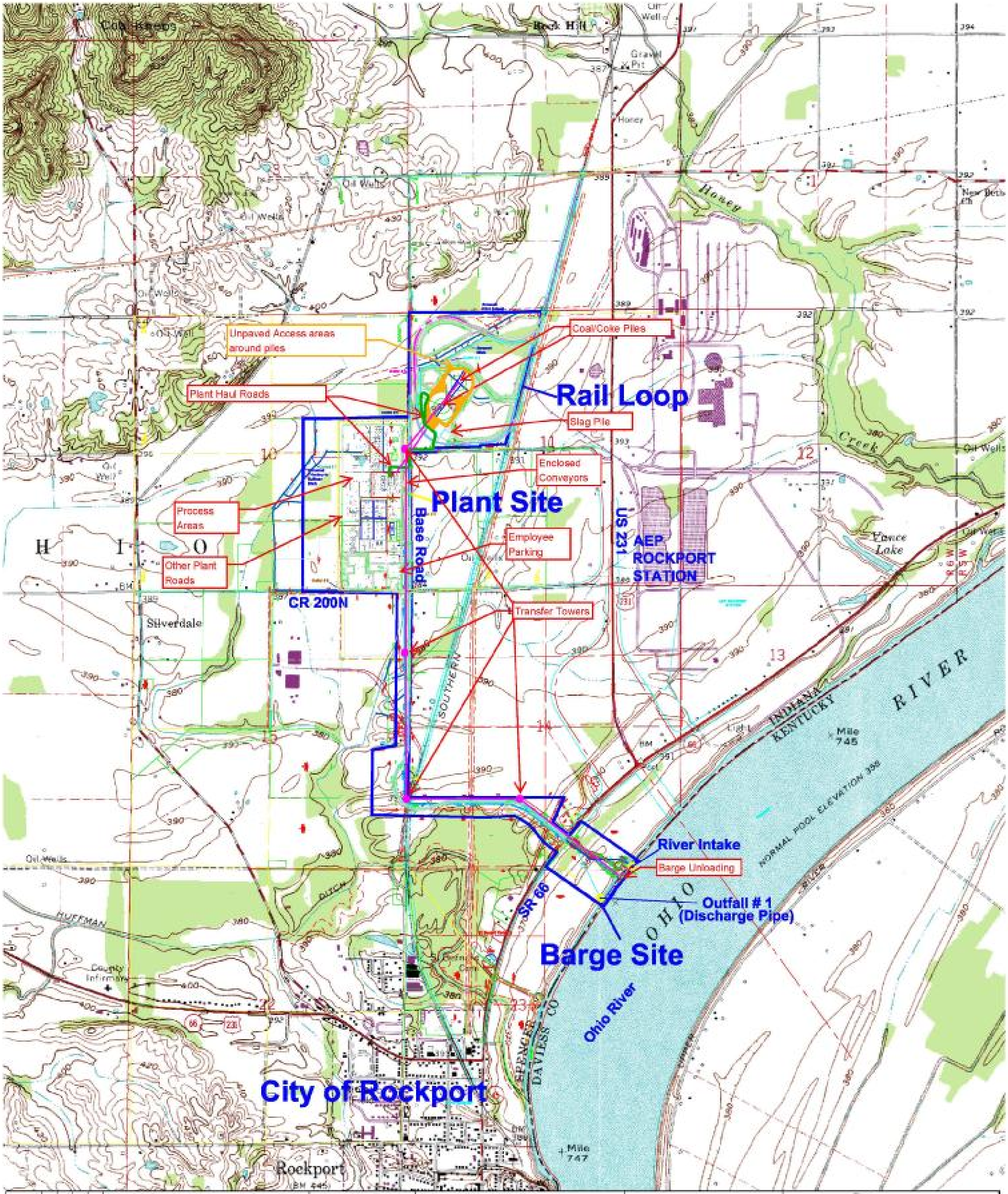
[65 FR 78285, Dec. 14, 2000, as amended at 73 FR 78213, Dec. 22, 2008]


See other Attachment for Conveyors and details inside Rail Loop

Enclosed Conveyors

Other Plant Roads

Air Permit Attachment



LOCATION MAP

Scale: NTS

12/10/2011

TSP

Indiana Gasification, LLC

Site Location Map

Revisions

No.	By	Date	Description
△		10-10-11	Rail Loop Revisions
△			
△			
△			
△			
△			

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Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a PSD/New Source Construction and Part 70 Operating Permit (Title V)

Source Description and Location

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Permit Reviewer:	**Josiah Balogun**

Public Notice Information

On December 15, 2011, the Office of Air Quality (OAQ) had a notice published in the Journal Democrat in Rockport, Indiana, stating that Indiana Gasification, LLC had applied for a PSD/New Source Construction and Part 70 Operating Permit (TITLE V) to operate a natural gas (SNG) and liquefied carbon dioxide (CO_2) production plant. The notice also stated that OAQ proposed to issue a Title V permit for this operation and provided information on how the public could review the proposed Title V permit and other documentation. Finally, the notice informed interested parties that there was a period of forty - seven (47) days to provide comments on whether or not this Title V permit should be issued as proposed.

On January 25, 2012, the Office of Air Quality (OAQ) held a public meeting and hearing at the South Spencer High School Auditorium in Rockport, Indiana, for citizens and interested parties to discuss questions and concerns related to the project.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

Comments Received from USEPA

On February 2, 2012, Sam Portanova of USEPA submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM’s corresponding responses.

Comment 1: The permit record does not appear to include any air quality analysis to show that this source will not cause a violation of the ozone national ambient air quality standards. 40 C.F.R. 51.166(k); 40 C.F.R. 51.166(m). EPA's 8-hour ozone implementation phase 2 rule (November 29, 2005; 70 FR 71612) requires that NOx be considered as an ozone precursor under PSD. One of the elements of that rule is a requirement that the PSD program regulations define the term “significant” for ozone to include 40 tons per year (tpy) of NOx. See 40 CFR 51.166(b)(23)(i). In accordance with 40 CFR 51.166(m)(1)(a), a permit application must contain an air quality analysis for each pollutant that a new source would have the potential to emit in significant amounts. Since the proposed Indiana Gasification permit has NOx emissions above this significance threshold for ozone, EPA regulations require that the record contain an ozone impact analysis for this source. A quantitative modeling analysis is not necessarily required, but IDEM should consult with EPA Region 5 regarding the appropriate form for such an analysis in this case. 40 CFR Part 51, Appendix W, §5.2.1.c. Although IDEM is in the process of adopting the requirements of the Phase 2 rule into the Indiana state implementation plan, even before those rules are finalized, EPA's expectation is that IDEM will conduct a source impact analysis on ozone for sources emitting NOx over the 40 tpy significance level for ozone to ensure that its permits are consistent with the Clean Air Act and the minimum requirements described in 40 CFR 51.166 for state PSD permitting programs.

Response 1: U.S. EPA explains in its letter responding to the Sierra Club's July 28, 2010, rulemaking petition to designate air quality models for ozone and $PM_{2.5}$ for use by all major sources applying for a PSD permit that, because "[t]he complex chemistry of ozone and secondary formation of $PM_{2.5}$ are well-documented and have historically presented significant challenges to the designation of particular models for assessing the impacts of individual stationary sources on the formation of these air pollutants," the Agency's position has been that it "was not technically sound to designate with particularity specific models that must be used to assess the impacts of a single source on ozone concentrations." Letter from Gina McCarthy, U.S. EPA Office of Air and Radiation, to Robert Ukeiley, 2 (Jan. 4, 2012). Instead, to comply with the requirements of CAA § 165(e)(3)(D), the Agency's practice has been to have its regional offices consult with state/local agencies on a case-by-case basis regarding the appropriate models or other analytical techniques that should be used. U.S. EPA Jan. 4, 2012, letter at 2; see 40 C.F.R. Part 51, Appendix W, Sec. 5.2.1.c ("Estimating the Impact of Individual Sources. Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the regional office to determine the most suitable approach on a case-by-case basis.")

IDEM has consulted with U.S. EPA Region 5 and explains below its analysis.

Ozone is a photochemical pollutant that is not generally emitted directly from sources, but is a secondary pollutant created through complex reactions, primarily from volatile organic compounds (VOCs) and oxides of nitrogen (NOx). This complex chemistry is well understood but has historically presented significant challenges to the designation of particular models for assessing the impacts of individual stationary sources for the formation of this pollutant. Since formation of ozone takes place over 10's to 100's of kilometers downwind from sources, regional models have been developed to simulate ozone levels over large areas. These models have worked well and have been used to develop strategies for reducing VOCs and NOx in order to attain the ozone ambient air quality standards. However, changes from additions of individual sources have not shown any impact in these regional models.

Given the limited significance of Indiana Gasification's emissions, 16 tons per year for VOCs and 127 tons per year for NOx, the analysis set forth below demonstrates that the IG project would not have an effect on the attainment status. Examining the point source emissions for Spencer County for 2010, VOCs and NOx account for 27,978 tons per year. Most of those emissions are coming from the AEP Rockport power plant. Indiana Gasification's potential emissions for VOCs and NOx are 143 tons per year for both pollutants, and would represent only 0.5% of the total of NOx and VOC point source emissions for the county. If other potential ozone precursor emitting sources are included, such as biogenics, area, and on/off road mobile source emissions for this county, this would decrease the percentage of IG's overall potential contribution for ozone formation. While production of ozone is not a linear relationship to emissions, analysis of IG's emissions demonstrates the impacts of this project will be below detectable levels. As described below, because it will only be emitting less than 0.5% of the emissions for that county, its ozone contribution would be insignificant and immeasurable.

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Since ozone is a regional pollutant as explained above and not just county specific, IDEM further evaluated the ozone formation in that area using the modeling analysis used in the Cross State Air Pollution Rule (CSAPR).

Ozone Analysis for Indiana Gasification – U. S. EPA's CSAPR Modeling

Because of the well established relationship between nitrogen oxides (NOx) and volatile organic compounds (VOCs), regional transport, and the formation of ozone, U.S. EPA recently finalized the CSAPR to assist states in meeting the ozone NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the ozone NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs).

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT), to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all ozone monitors in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of Indiana Gasification (IG), IDEM used the U.S. EPA modeling conducted to establish the final 2014 budgets in CSAPR. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding the NO_x emission reductions necessary to achieve the future year modeled design values can be found in the "EmissionsSummaries.xlsx spreadsheet under the Emissions Inventory Final Rule TSD section at EPA's CSAPR website for technical information, http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual NOx emissions for Indiana by 2014 at 431,342 tons and remedy control scenario annual NOx emissions by 2014 at 424,250 tons. Indiana's total NOx emission reduction between these scenarios is 7,092 tons. All surrounding states make similar significant reductions. IG emissions will be 127 tons per year of NOx and 15.9 tons per year of VOCs. For purposes of this analysis, the IG emissions will be analyzed at 143 tons per year.

8-Hour Ozone Modeling Results

The nearest ozone monitor to Spencer County is the Leopold ozone monitor in Perry County. Leopold's current design value for 2009-2011 is 70 parts per billion (ppb), below the 8-hour NAAQS of 75 ppb. The maximum 8-hour ozone modeled concentrations for Perry County are 73.1 ppb for the 2014 base case and 72.6 ppb for the 2014 control scenario. This is a reduction of 0.5 ppb as a result of NOx emission reductions from CSAPR. In order for this modeled annual concentration reduction from CSAPR to occur, Indiana's 2014 NOx emissions were reduced by 7,092 tons of NOx. This particular monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, thousands of tons of annual NOx emission reductions also will have occurred by 2014, many of which would impact this site. Therefore, to estimate the impact of IG on modeled concentrations, the ratio of IG NOx and VOC emissions to the NOx emission reductions from CSAPR are compared to the ratio of IG ozone impact by the difference between the base case and remedy control modeling results.

IG's impact on ozone is estimated as:
143 tons NOx and VOC/7,092 tons NO_x = 0.02 *0.5 ppb = 0.01 ppb of IG ozone impact.
This equates to only about 0.01% of the projected regional ozone level (2014 modeled Remedy results shown in the table below).

Table 1, below, shows the CSAPR modeling results for nearby ozone monitors and the impact that IG would have on ozone concentrations in the area. Base case and remedy concentrations come from tables located in CSAPR_AQModeling.pdf, Appendix B, pages B-10 and B-12 for 8-hour ozone design values that show the projected base case 2014 ozone concentrations at surrounding monitoring sites versus control strategy ozone concentrations. 2014 Base represents modeled results taken from the anticipated 2014 emissions. 2014 Remedy represents the 2014 Base emissions with emission reductions from CSAPR factored into the modeling.

Table 1: EPA's Cross-State Air Pollution Rule 8-Hour Ozone Modeling Results

Monitor ID	County	2014 Base (ppb)	2014 Remedy (ppb)	2014 Base-Remedy (ppb)	Anticipated Source Impact (ppb)	Source (IG) Impact of 2014 Remedy (%)
181230009	Perry	73.1	72.6	0.5	0.01	0.0138%
180710001	Jackson	66.2	65.8	0.4	0.008	0.0122%
181730008	Warrick	71.6	71.3	0.3	0.006	0.0084%
181730009	Warrick	65.7	65.3	0.4	0.008	0.0123%
181730011	Warrick	69.0	68.7	0.3	0.006	0.0087%

Based on this analysis, IG's impact to regional ozone is expected to be only about 1/100th of one percent. To further show the impact this increase would have upon monitoring results, the method detection limit for ozone monitors used in Indiana ozone monitoring network is 0.5 ppb. Values contained in Table 1 (0.01 ppb or less) would not be measurable.

Summary

Indiana Gasification's NOx and VOC emissions were compared with U.S. EPA CSAPR modeling for 8-hour ozone to determine what impacts on ozone may occur as a result of ozone formation. When the IG emissions were compared with the amount of NOx emission reductions realized from CSAPR and compared with CSAPR modeling results for 8-hour ozone, the impacts from IG on nearby ozone monitors in Perry, Warrick and Jackson Counties are anticipated to be below detectable levels and would not have an effect on the attainment status of those counties.

Comment 2: The draft permit does not show the potential to emit (PTE) for total GHG emissions. Please add the GHG PTE to the permit, either on a mass basis for the individual GHG gases or on a CO_2 equivalent (CO_2e) basis. The GHG PTE should account for CO_2 emissions and any other GHG emitted from the facility (e.g., methane, nitrous oxide).

Response 2: The PTE for total GHG—expressed as CO_2e—is fully documented in the TSD for each emissions unit and for the facility as a whole (*see* TSD pages 7 and 9–11, as well as emissions tables at end of TSD document, starting on page 398 of the 880-page PDF).

Comment 3: The draft permit contains emission limits for CO_2, but does not contain limits for other GHG pollutants. Please clarify, in the permit record, how compliance will be demonstrated for any non-CO_2 GHG emitted from the facility.

Response 3: CO_2 was selected as a surrogate for point source CO_2e emissions for three reasons. First, the other point source GHG emissions are incidental to combustion and have a direct relationship to and are proportionate to fuel use and the associated CO_2 emissions. Thus, limitations on CO_2 will directly and proportionately limit non-CO_2, point source GHG emissions. Second, point source GHG emissions at the proposed facility total 2.18 tons per year CH_4 and 0.34 tons per year N_2O, for a total of 151.18 tons per year CO_2e. Point source CO_2 emissions from this proposed facility total 1,875,000 tons per year. The relative contribution of CH_4 and N_2O to total point source CO_2e (0.0081%) is insignificant and does not warrant separate limits. Third, the principal source of CH_4 and N_2O is fuel combustion in the auxiliary boiler and engines, and there are no known supplemental controls for such units that could support rational separate emission limits for those GHGs. Consequently, CO_2 was selected as the surrogate for all point source GHG emissions at the proposed facility. Compliance for GHGs other than CO_2 from such sources can and will be demonstrated through the emission limits for CO_2. The explanation of this approach is in the current record at several points. (For example, see TSD BACT Analysis text at page 149 of 181).

The only instances where CO_2 is not an adequate surrogate are in the case of fugitive SF_6 emissions from circuit breakers (FUG-SF6), and fugitive CH_4 emissions from equipment (FUG). For this reason, emissions of these GHG pollutants are addressed with appropriate permit conditions for those pollutants and the processes from which they are emitted (*see* BACT analysis in TSD for emissions units FUG and FUG-SF6).

Comment 4: Please clarify, in the permit record, whether there are any GHG emissions from the gasifier.

Response 4: No. The gasifier is not an emission source except for small amounts of fugitive emissions, which are included in the emission calculations together with other fugitive emissions and described as FUG emissions. There are GHG emissions associated with the pre-heat burners, identified as EU-008A-E. IDEM wrote a GHG BACT analysis for these emission units and also established a limit for them in the permit.

Comment 5: The flare minimization plan requirement (permit conditions D.2.4(1)(D), D.2.4(2)(C), D.2.4(3)(B), and D.2.4(B)) for this unit applies during startups, shutdowns, and other flaring events. The best available control technology (BACT) emissions limits for $PM/PM_{10}/PM_{2.5}$, CO, SO_2, and NOx apply to startup and shutdown, but does not mention limits for other flaring events. Since BACT applies at all times, the permit should include BACT limits that apply during other flaring events. The permit may specify different BACT limits that apply during other flaring events but cannot exclude BACT limits during those events.

Response 5: US EPA is correct that the numeric emissions limits in the permit for flaring events are applicable only to startup and shutdown events (e.g., Condition D.2.4(1)(D)). This is because startups and shutdowns are the only operating scenarios in which flaring is expected in normal operation. Outside of startups or shutdowns, in normal operation the only emissions from the flare will be the combustion emissions from the pilot. The term "other flaring events" referenced in the permit condition regarding requirements of a flare minimization plan (e.g., Condition D.2.4(1)(A)) is referring to upsets or malfunctions. For this facility, upset flaring is anticipated to be very infrequent. However, as explained more fully in response to Sierra Club Comments 5 and 78, due to the inherently unpredictable nature of malfunction events, IDEM is requiring IG to implement extensive BACT work practice requirements which apply during malfunction flaring, instead of numeric limits. These work practices are required at all times and include use of flare best practices (e.g., Condition D.2.4(1)(B)) and a requirement to follow the flare minimization plan (e.g.; Condition D.2.4(1)(A)) which includes, among other requirements, a requirement to investigate the "root cause" of malfunction events that cause gases to be sent to a flare, and implementation of preventative measures to minimize re-occurrence of these events. Thus, the permit contains numeric BACT emission limits which apply to planned flaring (startups and shutdowns), and BACT design/work practice requirements which apply at all times.

Comment 6: Permit condition D.2.4(3)(B) limits SO_2 emissions during a shutdown event to 85.21 pounds per hour (lb/hr) or 255.6 lb per 24-hour period. The technical support document lists SO_2 emissions from this flare as 1.97 tpy. However, the 255.6 lb per 24-hour limit could result in maximum SO_2 emissions of 46.65 tpy. Given the disparity between the projected limits and the maximum potential limits, please explain how the source expects to limit the total frequency and duration of shutdown events.

Response 6: The annual flare SO_2 emissions estimate of 1.97 tpy is based on a conservative estimate of the number of startups and shutdowns per year. It is comprised of an estimated 0.05 tpy startup flaring and 1.92 tpy of shutdown flaring. To ensure that the frequency and duration of these events are consistent with this permit evaluation, annual limits of these amounts for startup and shutdown will be added to the permit. The same monitoring and recordkeeping required to comply with the daily limit will support demonstration of compliance with these annual limits. The quarterly reports form for the SO_2 emissions have been added to the permit.

D.2.4 PM, PM_{10} and $PM_{2.5}$, CO, SO_2, NOx and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Syngas Hydrocarbon Flare, identified as EU-001 shall be as follows:

....

(3) The SO_2 emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

....

The SO_2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lbs per 24 hours **and shall not exceed 1.92 tons per twelve (12) consecutive month period with compliance determined at the end of each month**. The SO_2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3-hour average **and shall not exceed 0.05 tons per twelve (12) consecutive month period with compliance determined at the end of each month**.

Comment 7: Permit conditions D.4.9(c) and D.4.9(d) list a CO_2 BACT emission limit of 1,290,000 tpy for the AGR units that represents a significant reduction in emissions compared to the first two years of operation. This CO_2 reduction is to be achieved by the production of liquified CO_2 that will be sold to third parties for use in enhanced oil recovery. Permit condition D.4.16 includes a compliance determination method for CO_2 emissions; however, this condition does not appear to account for monitoring CO_2 emissions from the liquefaction process. The permit should include a monitoring requirement that accounts for the removal of CO_2 from the AGR emission stream in order to demonstrate compliance with the 1,290,000 tpy limit for emissions of CO_2 from the facility.

Response 7: With respect to monitoring the CO_2 from the AGR vent, the AGR will isolate CO_2 to produce a 98% pure CO_2 stream. (See IG Permit Application Section 2.0). That CO_2 is either compressed and liquefied for sale or routed to one of the RTOs prior to venting. Flow to the RTOs is to be monitored continuously as anticipated by Draft Permit Conditions D.4.11 and D.4.24(d). CO_2 emitted through the AGR vent (outlet of the RTO) is determined using the method set forth in Draft Permit Condition D.4.16, which takes into

account the flow and the CO$_2$ concentration of flow to the RTOs.
While monitoring and recordkeeping of the vent flow from the AGR to the RTOs is required in the proposed permit, a permit language amendment in Section D.4 will make clear the requirement to calibrate, maintain and operate those flow meters.

With respect to the monitoring of CO$_2$ emissions from the liquefaction process, liquefaction is performed through electric-power compressors that do not themselves emit combustion-related CO$_2$. The fugitive CO$_2$ emissions from the compressors are addressed in the leak detection and repair requirements of permit condition D.15.4. The CO$_2$ emissions from the compressors are estimated as no more than 4 tons per year (see TSD at page 11).

The following changes have been made in the permit.

D.4.22 Vent Flow Monitoring

In order to demonstrate the compliance status with Conditions D.4.6 – SO$_2$ PSD BACT, D.4.9 - GHGs PSD BACT, D.4.11 – HAPs Minor Limit, D.4.15 – Sulfur Dioxide Control, and D.4.16 - Greenhouse Gases (GHGs) Calculations, a continuous monitoring system shall be calibrated, maintained, and operated on AGR vent flow to continuously monitor the vent flow from the AGR to the thermal oxidizers. For the purposes of this condition, continuous monitoring shall mean no less often than once per fifteen (15) minutes. The output from this monitoring system shall be recorded whenever the AGRs are in operation.

....

D.4.2~~3~~**4** Record Keeping Requirements

....

(d) To document the compliance status with condition D.4.11, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly when the unit is in operation and shall be complete and sufficient to establish compliance with the HAP emission limits established in condition D.4.11.

(1) The monthly records of the ~~flow rate of gas vented to the thermal oxidizer~~ **methanol, carbonyl sulfide, and total HAPs emissions**.

(2) ~~The temperature of the~~ **Monthly records of when the** RTO **is in standby mode**.

(3) The water flow rate of the water wash tower (if used).

(4) The results of the most recent stack test ~~showing~~ **setting** the **emission factors for** ~~thermal oxidizer destruction efficiency for VOC and~~ methanol, **carbonyl sulfide, and total HAPs emissions** ~~and inlet and outlet methanol and VOC concentrations during the test~~.

(e) In order to document the compliance status with Conditions D.4.6 – SO$_2$ PSD BACT and D.4.15 – Sulfur Dioxide Control, the Permittee shall maintain monthly records of the sulfur content in the AGR vent stream.

(f) In order to document the compliance status with Condition~~s~~ **D.4.22 - Vent Flow Monitoring,** ~~D.4.6 – SO$_2$ PSD BACT, D.4.9 - GHGs PSD BACT, D.4.15 – Sulfur Dioxide Control, and D.4.16 - Greenhouse Gases (GHGs) Calculations~~, the Permittee shall maintain monthly records of the vent flow from the AGRs into the RTOs.

....

Comment 8: A continuous emission monitoring system (CEMS) for NOx, SO_2, and CO_2 is being proposed for the wet sulfuric acid (WSA) plant but not the AGR system vent. Since the AGR vent is the largest source of GHG emissions from the facility, please clarify whether a CO_2 CEMS was considered for the AGR vent and, if so, why a CO_2 CEMS was not included in the draft permit.

Response 8: There are three substantial differences between the WSA and the AGR relevant to whether a CO_2 CEMS is appropriate:

First, in contrast to the AGR stream described below, the concentration of the CO_2 in the WSA can vary based on composition of the feedstock and the relative portions of coal versus coke feed. The composition of the gas being emitted from the AGRs will not vary significantly. The AGR stream for pipeline quality requirements will be nearly pure CO_2, with the rest being mostly CO which combusts in the RTO to CO_2. The compliance demonstration calculation for the AGR/RTO emissions of CO_2 accounts for the CO_2 in the exhaust, as well as the CO and organics that are converted to CO_2. Due to conservative default factors, the equation in the permit at Section D.4.16 results in all the flow being treated as CO_2. Any variability that would occur would be within the 1% relative accuracy of CO_2 concentration in a CEMS. Accordingly, a CEMS will offer no improvement in the CO_2 tracking of this source.

Second, the WSA will already have NOx and SO_2 CEMs and, therefore, the incremental cost to add and maintain a CO_2 CEM is less for the WSA. In contrast, no other CEMS is required for the AGR vent.

Third, the AGR vent will operate only intermittently, whereas the WSA will be operated continuously.

Therefore, monitoring AGR vent flow to the RTO is the appropriate monitoring requirement and provides a continuous and accurate method of quantifying and tracking emissions of CO_2 from this source.

Comment 9: Permit condition D.4.11 limits methanol emissions at the AGR units to 9.0 tons per 12-month period and combined hazardous air pollutant (HAP) emissions to 22.5 tons per 12-month period so that the source remains below the major source threshold for HAPs. The permit includes monitoring, reporting, and recordkeeping requirements for the methanol limit; however, the permit does not include monitoring requirements to assure compliance with the combined HAP limit. Furthermore, we note that the calculations attached to the draft permit document show potential HAP emissions above the 25 tpy major source threshold. Please include monitoring requirements in the permit to assure compliance with the combined HAP emissions limit.

Response 9: The requirements for HAPs associated with the AGR units are being revised in response to this comment. In particular, a limit on COS is being added, the total HAPs limit for the AGR is being reduced, the stack testing of the RTOs is being expanded to include a broader spectrum of organic HAPs, and a requirement to use that testing to set emissions factors for HAPs for the AGR is being added. In addition, the method for demonstrating compliance with the methanol limit on the AGR units is being revised to simplify the equation, and the method for demonstrating compliance with the COS and total HAP limits on the AGR units are being added.

Below is the revised language for conditions D.4.11 and D.4.19 that address compliance with the HAP limits on the AGR units.

D.4.11 Hazardous Air Pollutants (HAPs) Minor Limits

(a) The Acid Gas Recovery Units, identified as EU-007A/B, Methanol **and Carbonyl Sulfide (COS)** emissions shal**l, each** be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The Acid Gas Recovery Units, identified as EU-007A/B, combined Hazardous Air Pollutants (HAPs) emissions shall be limited to less than ~~22.5~~ **17.0** tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The methanol emissions from the AGRs shall be calculated by the following equation:

Methanol emissions = Vent Flow x Methanol ~~Conc. x (1 – Control Effic.)~~ **Emissions Factor**

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period)
to be monitored continuously by the Permittee.

Methanol ~~Conc.~~ **Emissions Factor** = Methanol ~~Concentration~~ **emitted per million standard cubic feet of vent gas** ~~of the inlet~~ to the thermal oxidizer (lbs methanol/~~million~~ **MM**SCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. Until the initial compliance stack testing is performed, the engineering estimate of ~~12.7~~**0.127** lbs methanol **emitted**/million SCF **of vent flow** shall be used.

~~Control Effic. = The control efficiency of the Regenerative Thermal Oxidizer as determined by stack test. Until the initial stack test is performed, the engineering estimate of 99% control shall be used.~~

(d) The carbonyl sulfide emissions from the AGRs shall be calculated by the following equation:

Carbonyl Sulfide emissions = Vent Flow x Carbonyl Sulfide Emissions Factor

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period)
to be monitored continuously by the Permittee.

Carbonyl Sulfide Emissions Factor = Pounds of Carbonyl Sulfide emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. COS/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. Until the initial compliance stack testing is performed, the engineering estimate of 0.0062 lbs. carbonyl sulfide emitted/million SCF vent gas shall be used.

(e) Total HAP emissions from the AGRs shall be calculated by the following equations:

When there is no AGR vent flow and RTO is in Standby Mode:

Total HAPs Emissions = RTO Fuel Flow in MMBtu/hr. x HAP Emission Factor of 0.00185 lb HAP/MMBtu

When there is AGR vent flow to the RTO:

Total HAP emissions = Methanol Emissions + Carbonyl Sulfide Emissions + Other HAPs Emissions

Where:

Methanol Emissions = Methanol Emissions as quantified in D.4.11(c)

Carbonyl Sulfide Emissions = Carbonyl Sulfide Emissions as quantified in D.4.11(d)

Other HAPs Emissions are calculated by the following formula:

Other HAPs Emissions (with AGR vent flow) = Vent Flow x (Hexane Emissions Factor + Formaldehyde Emissions Factor + Additional HAPs emissions factor)

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period) to be monitored continuously by the Permittee.

Hexane Emissions factor = Pounds of Hexane emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. hexane/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the emission factor of 0.0054 lbs. hexane emitted/million SCF vent gas shall be used.

Formaldehyde Emissions factor = Pounds of Formaldehyde emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. formaldehyde/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the emission factor of 0.00023 lbs. formaldehyde emitted/million SCF vent gas shall be used.

Additional HAPS Emissions factor = Pounds of any other HAP besides methanol, carbonyl sulfide, hexane, or formaldehyde emitted per million standard cubic feet of vent gas to the thermal oxidizer (lbs. HAP/MMSCF of vent gas) as determined in the most recent compliance stack test of the oxidizer. If no compliance stack test has been performed, the emission factor of 0.00004 lbs. additional HAPs emitted/million SCF vent gas shall be used.

Compliance with the above limits and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

………

D.4.19 Testing Requirements [326 IAC 2-1.1-11]

………

(d) In order to demonstrate compliance with Condition D.4.11 – Hazardous Air Pollutants Minor Limit, not later than 180 days after initial startup of the second gasifier, but not later than 365 days after the initial startup of the first gasifier, the Permittee shall conduct methanol**, carbonyl sulfide and other HAPs (as determined by IDEM, using the results of the screening test required by Condition D.4.19(e))** emissions stack testing of the emissions from the first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has been started up. Not later than 180 days after initial startup of the fourth gasifier, the Permittee shall conduct methanol **carbonyl sulfide and other HAPs** emissions stack testing of the emissions from the other of the Acid Gas Removal (AGR) units EU-007A or EU-007B. These tests shall utilize methods as approved by the Commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) Not later than 60 days prior to the emissions stack testing required by Condition D.4.19(d), the Permittee shall conduct a screening test for other HAPs present in first of the Acid Gas Removal (AGR) units EU-007A or EU-007B that has started up. These tests shall utilize methods as approved by the Commissioner. This requirement shall also apply to the repeat testing required by Condition D.4.19(d). Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Comment 10: Section D.5 lists permit conditions for two WSA plant trains (EU-015A-B). In permit condition D.5.8, NOx is limited to 10.2 lb/hr based on a 24-hour block daily average when the flow to the selective catalytic reduction (SCR) is operating above its optimal temperature of 750 degrees F. However, there is no limit established for when the flow to the SCR is below 750 degrees F. Since BACT must apply at all times, the permit should include a limit for these units when the flow to the SCR is below 750 degrees F.

Response 10: The BACT limit of 10.2 lbs/hr, block 24-hr average NOx from the WSA is intended to apply at all times. The facility is capable of maintaining the minimum SCR operating temperature of 750 F at all times acid gases are being fed to the unit. The only period when temperatures will be below this temperature is during initial WSA startup/warmup phase, before the introduction of acid gas feed. During the unit's warmup phase, the unit will use natural gas-fired preheat burners to get the unit up to this operating temperature. Uncontrolled emissions of the preheat burners, without any SCR effectiveness, are estimated to be only 2.45 lbs/hr (see draft permit TSD pdf document, page 444 of the 880 pdf). Therefore, even during this brief period of operation below 750F, the facility will comply with the proposed 10.2 lb/hr BACT limit. Consequently, there is no need for the qualifier in the BACT permit limit related to operating temperature. Instead, the NOx BACT permit limit for the WSAs will be amended to apply at all times, dropping the exception for temperatures below 750 F, with SCR required when acid gases are being fed to the unit.

This will require the following changes to the permit:

D.5.8 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Wet Sulfuric Acid (WSA) plant, identified as EU-015A and B shall be as follows:

~~The NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be limited by the use of a selective catalytic reduction (SCR) when the flow to the SCR is at or above a temperature of 750 degrees F and the~~. **The** NOx emissions shall not exceed 10.2 pounds per hour NOx based on a 24-hour block daily average for each Wet Sulfuric Acid unit~~.~~ **and, when acid gases are being fed to the unit, the NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by the use of selective catalytic reduction (SCR).**

D.5.12 Nitrogen Oxide Control

In order to ensure compliance with Condition D.5.8, the selective catalytic reduction (SCR) shall be in operation and control emissions from each Wet Sulfuric Acid (WSA) unit at all times that ~~the WSA is in operation and the flow to the SCR is at or above 750 degrees F~~ **acid gases are being fed to the unit**.

~~D.5.19 WSA Temperature Monitoring~~

~~In order to demonstrate the compliance status with Conditions D.5.8, the Permittee shall continuously monitor the temperature of the flow to the SCR whenever the WSA is operating and the SCR is not operating.~~

D.5.2**0**~~1~~ Record Keeping Requirements

....

~~(e) To demonstrate compliance with Condition D.5.19, the Permittee shall record the output of the continuous temperature monitoring system on the flow to the SCR.~~

(~~f~~**e**) Section C - General Record Keeping Requirements, contains the Permittee's obligation with regard to the records required by this condition.

Comment 11: Section D.7 includes PM, PM$_{10}$, PM$_{2.5}$, CO, SO$_2$, and NOx BACT emission limits for the five gasifier preheat burners (EU-008A-E). However, the limits themselves are based on the emissions for only one gasifier preheat burner operating under normal conditions of 18 MMBTU/hr, not all five gasifiers operating at the site. It is unclear whether this condition is meant to apply individually to each gasifier or collectively to all five gasifiers operating at once. We note that the calculations attached to the draft permit (pages 417-426 and 508-517 of the electronic file) contain emission factors and equations necessary for obtaining the BACT limits. The limits listed are for an individual gasifier preheat burner as opposed to all five preheat burners. Please clarify in the permit the BACT limit(s) that applies to the five gasifier preheat burners.

Response 11: IDEM has revised these conditions to clarify that the limits apply to each of the Gasifier Preheat Burners in the permit accordingly.

D.7.4 PM, PM$_{10}$ and PM$_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The PM, PM$_{10}$ and PM$_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0007 lb /MMBtu**, each** and only natural gas or SNG shall be used.

D.7.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.056 lb CO/MMBtu**, each** and shall use good combustion practices.

D.7.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be not exceed 0.0006 lb SO_2/MMBtu**, each** and natural gas or SNG shall be used.

D.7.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Gasifier Preheat Burners, identified as EU-008A - E shall be as follows:

The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.10 lb NOx /MMBtu**, each** and good combustion practices shall be used.

Comment 12: Section D.18 lists permit conditions for the zero liquid discharge (ZLD) inert gas vent (EU-033). Permit condition D.18.4 says that operation of the carbon adsorber (for mercury emissions) will allow the source to limit source-wide HAP emissions to less than 10 tpy of a single HAP and to less than 25 tpy of all HAPs. However, the condition does not provide a specific HAP limit for this unit. If use of this control device is necessary to limit source-wide HAPs to less than 10/25 tpy, then the permit should include an emission limit for this unit in order to demonstrate that the source is not a major source for HAPs. According to the calculations attached to the draft permit, a limit on mercury emissions from this unit is not necessary to limit source-wide HAP emissions below the 10/25 tpy threshold. If these calculations are correct, the permit should clarify that this control option is not required to keep HAP emissions below 10/25 tpy.

Response 12: Besides the requirement to apply GHG BACT, there are no other states or federal regulations specifically applicable to this small process vent. However, IG intends to route this vent through a carbon adsorber control device to assure minimal mercury emissions and, as such, the carbon adsorber device will serve to reduce a hazardous air pollutant (HAP) to the extent such HAP does exist in the stream. Because a limit on mercury emissions from this unit is not necessary to limit source-wide HAP emissions below the 10/25 tpy threshold, this condition will be revised as follows:

D.18.4 Hazardous Air Pollutants (HAPs) Control

……

~~Compliance with this condition and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.~~

Comment 13: We have identified the following typographical errors in the permit:
In permit condition D.5.22, 326 IAC 3-5-7(5) should be 326 IAC 3-5-7(c)(4).

Response 13: IDEM has corrected the typo in Condition D.5.22 in the permit accordingly.

D.5.2~~2~~**1** Reporting Requirements

(a) Pursuant to ~~326 IAC 3-5-7(5)~~ **326 IAC 3-5-7(c)(4)**, reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

……

Comment 14: We have identified the following typographical errors in the permit:
In permit condition D.6.17, 326 IAC 3-5-7(5) should be 326 IAC 3-5-7(c)(4).

Response 14: IDEM has corrected the typo in Condition D.6.17 in the permit accordingly.

D.6.1~~7~~**8** Reporting Requirements

(a) Pursuant to ~~326 IAC 3-5-7(5)~~ **326 IAC 3-5-7(c)(4)**, reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

……

Comments Received from the Public

IDEM also received comments from a substantial number of citizens which are all addressed in this document. Not all of these commenters are identified specifically by name in this document, but all comments received during the public comment period are available for review as part of the public file.

The summary of the comments and IDEM, OAQ responses, including changes to permit No T147-30464-00060 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Section C Comments:

Comment 1: Section C.4 - Incineration allows incineration of refuse; it does so by restricting such to that allowed by cited statutes, which allow incineration of a limited amount of waste. No incineration should be permitted as it is unnecessary and unlikely to be closely monitored as to content. Why is incineration permitted at all at this facility?

Response 1: This permit condition is included in all Indiana Title V permits. It does not allow the source to incinerate refuse or any refuse burning. Any such incineration or burning of refuse would violate Indiana's air rules unless the source first obtains the proper air permitting approval. This permit condition emphasizes these legal requirements. There is no such approval in this permit. The permit condition states:

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

Comment 2: Section C.11 specifies that monitoring of emissions may begin as long as 90 days after start of operations. It could and should begin when operations begin; why isn't this required?

Response 2: Sources that are constructing new emission units are allowed 90 days after those units begin operation to get monitoring equipment and processes running correctly. New monitoring equipment for new units require analysis and evaluation to confirm that they are running correctly and that the data they collect is being recorded properly. This provision gives the source 90 days to complete these evaluations before they are in violation of the monitoring requirements. The source must still comply with all of its emission limits and standards once it begins operation. IDEM does not have to have emission monitoring data to cite a source for an emission violation or require the source to test its equipment if IDEM feels it is not operating properly.

Comment 3: Section C.13 (a) grants up to 180 days from the commencement of operations for the operator to file its Emergency Reduction Plan. This plan should exist the day operations begin, unless the operator can prove no emergency will arise for the first 180 days of operation: an impossibility due to the definition of emergency. What specific actions will be required to be taken, and which taken in the event of an emergency prior to the emergency Reduction Plan existing? What is the worst case scenario of such an emergency and what would be the potential injuries from it? Who will monitor emissions during such an emergency and who compensate the public and individuals for damages caused by the emergency?

Response 3: The Emergency Reduction Plan requirement for this source is based on the Indiana rule found at 326 Indiana Administrative Code (IAC) 1-5-2. All of the Indiana Administrative Code can be found at http://www.in.gov/legislative/iac/ on the Internet. The rule provides that the source has one-hundred eighty days from the date it commences operation to submit its emergency reduction plan. IDEM cannot shorten this time period as it is set out in the rule.

The Episode Alert Levels rule, 326 IAC 1-5 establishes air pollution episode levels based on concentrations of criteria pollutants in the ambient air. If these levels are reached, the Commissioner of IDEM will activate an Air Pollution Alert that will state the appropriate episode level. At that time the source must take the steps in its emergency reduction plan to reduce its emissions, pursuant to the episode level that has been declared.

IDEM monitors the level of air pollutants in the ambient air at established locations throughout Indiana. The actual monitoring data collected is available at http://www.in.gov/idem/4652.htm on IDEM's website. The air concentrations of each pollutant that would cause an air episode alert are set out in 326 Indiana Administrative Code 1-5-4. In the twenty-four years that this rule has been in place, ambient air levels have never been high enough to trigger an alert. If an alert were to occur, IDEM would continue to monitor the ambient air levels and would verify that all sources have reduced their emissions in compliance with their Emergency Reduction Plan. The rule does not set out any provision for compensation to the public or individuals for damages caused by the air pollution episode.

The emergency reduction plan does not govern what the source does if it has an emergency that affects its operation, such as a fire. If a source has an emergency it still must comply with all federal and state health-based emission standards. An emergency may constitute an affirmative defense to an action brought for noncompliance with a technology-based emission standard if the source meets all the requirements of 326 IAC 2-7-16. These requirements are set out in the Emergency Provisions condition in section B of the permit, including that the source must take all reasonable steps to correct the emergency.

IDEM has an Emergency Response team that responds to environmental emergencies around the state. These team members will evaluate any threat to the public and assist in determining what steps are necessary to protect the public. Any environmental emergency should be reported to IDEM immediately at (888) 233-7745. This number is answered 24 hours-a-day, 7 days-a-week.

Comment 4: Section C.16 allows an infinite number of days to retest after a failed stack test. The follow up stack test should immediately follow corrective action. What justifies not requiring immediate retesting?

Response 4: The permit condition, Actions Related to Noncompliance Demonstrated by a Stack Test, does not give the source an infinite number of days to retest after a failed stack test. The condition requires that the source retest no later than 180 days after the date of the noncompliant test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ has the power to extend the retesting deadline further.

Immediate retesting is not usually possible. Emission tests procedures can take days to run and require extensive preparation of testing equipment. The testing must be done pursuant to a testing protocol that must be submitted to IDEM in advance for approval. IDEM staff have to schedule time to observe the testing process. The source's plant operation staff and the testing personnel need time to evaluate why the operation failed the test and take corrective action before retesting can be carried out.

Please note that this condition does not excuse the source from failing its stack test. As stated in subpart (C) IDEM may take any action allowed under law in response to the noncompliant test, which could include taking an enforcement action against the source.

This permit condition states:

Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]
(a) When the results of a stack test performed in conformance with Section C – Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.
(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline
(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.
The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Comment 5: Section C.18 (d) (2) requires calculation of emissions. Emissions should be required to be measured because calculations are not based upon continuous nor even frequent, in most cases, monitoring of actual emissions. Actual emissions are measured, not calculated. What justifies not requiring reporting of actual measured emissions?

Response 5: This permit condition, the General Record Keeping Requirements condition in section C, sets out the general record keeping requirements for the source. This condition is used to make sure that there are a set of record keeping requirements that cover all the applicable requirements that apply to the source. Please note that all of the specific record keeping requirements for the source's emission units are set out in each of the D sections of the permit.

Part (d) of the General Record Keeping Requirements condition in section C applies to a particular circumstance under the air permitting rules. The requirements of provision (d) come directly from the applicable requirement at 326 IAC 2-2. The rule requirements are being incorporated into the permit.

Regarding the specific applicability and requirements of this rule, at some point in the future, after it begins operation, the source may make a change in the way that it operates an emission unit that does not require an air permit change under 326 Indiana Administrative Code 2-2 or 2-3, because there is no increase in emissions that would trigger new air permitting review under those rules. However, the source must monitor the emissions from the unit as required in (d)(1) of this condition and, using this monitoring information, calculate its annual emissions in a tons per year units as required in (d)(2) of this condition. So, the actual emissions from the unit would be monitored, not calculated. The monitored emissions would then be converted to units of “tons per year” through a calculation and recorded.

Greenhouse Gases (GHGs) Comments:

Comment 6: Page 12 of 43 of the UPTE charts, Note 2, shows a serious amount and increase of CO_2 emissions in the first two years of operation. This indicates that unnecessary emissions will occur, that or the CO_2 capture process is not perfected. What is the cause of these variations in CO_2 emissions over time? How will the capture of CO_2 be accomplished? Where will the CO_2 be stored or how will it be removed from the site?

Response 6: With respect to the commenter’s use of the phrases “CO_2 capture process,” “capture of CO_2” or “CO_2 be stored or removed from the site” to describe the manufacture of CO_2 as a product for sale, it should be clarified that the CO_2 is produced in the gasification and purification process and is not “captured” from an emission unit. (See Response to Public Comment 9). Furthermore it is not stored at the Indiana Gasification site. The cause of the variations in CO_2 emissions from the AGR vent in the first two years of operation are described on page 155 of 181 of the TSD BACT Analysis, and the variations are reflected in the enforceable permit conditions in Draft Permit Condition D.4.9.

Comment 7: The plan calls for a pipeline to Louisiana for transporting liquid CO_2 captured by the plant, so that CO_2 can be used to enhance oil recovery from old wells. There is no assurance that this pipeline will ever be built. The plant proposes to operate the first two years without CCS. I predict that at the end of two years the plant owners will say, no pipeline, I guess we will have to continue dumping millions of tons of CO_2 into the atmosphere. Otherwise, we would have to shut-down the plant and layoff 200 plant workers." Enhanced oil recovery is an established means of sequestering CO_2. CCS is the object of intense current research, and it is by no means clear that a safe and economic solution will be found. Even with 80 percent CCS, the plant will unnecessarily increase CO_2 emissions above those entailed with burning natural gas. In addition the plant will subsidize destructive coal mining, which itself releases significant amounts of climate altering methane, even before it gets to the plant.

Response 7: Draft Permit Condition D.4.9 expressly prohibits what this commenter speculates will occur by providing enforceable limits on CO_2 emissions from the AGR vents. With respect to the comments on the emissions associated with the use of natural gas and “subsidization” of coal mining, they are beyond the scope of the permitting action being taken here consistent with the Clean Air Act PSD permitting process and the state air permitting rules.

Comment 8: This project has shown a lot of progress in reducing CO_2 emissions but despite the progress shown by the CO_2 emission limit in the Draft Permit, it simply does not include sufficient limits on future CO_2 emissions from the Project, given the record available below.

The Indiana Air Pollution Control Board has adopted this rule into its PSD program. *See*

326 I A C 2-2-1(zz)(1) (including facilities that emit 75,000 CO_2e, or 100,000 CO_2e if the project is built after July 1, 2011, in the definition of “subject to regulation”). The Project will exceed this applicability threshold, and thus IG was required to perform a greenhouse gas BACT analysis. The inclusion of a CO_2 emission limit is therefore required for this facility. *See* Draft Permit Condition D.4.9 (establishing CO_2 emission limit of 1.29 million tpy during and after the third 12 months of operation).

The Project’s CO_2 emission limit is based – at least in part – on IG’s intent to use the AGR unit to capture and sell more than 90% of the CO_2 produced at the facility. *See* Application, Appx. F at 2-7. However, IG believes that operational constraints, including potential downtime of the CO_2 pipeline and downstream offtakers, as well as maintenance and other issues within the facility itself, may result in the amount of CO_2 actually placed into the pipeline to be only about 80% of the potential CO_2 emissions from the AGR. Thus, the CO_2 emission limit represents the balance of the potential AGR emissions that can be vented, 1.29 million tpy during the third 12-month period of operation and each year thereafter.

The 1.29 million tpy limit is the third of a three-phase CO_2 BACT emission limitation. We support the use of such a limitation, and note that similar limitations have been upheld by the Environmental Appeals Board (“EAB”) when a “permitting authority [is] faced with some uncertainty as to what emission limit [is] achievable.” *In re AES Puerto Rico L.P.,* 8 E.A.D. 324, 349 (E.A.B. 1999). For example, EAB upheld a BACT emission limits for nitrogen oxides by using both a design limit and a worst-case limit. *In re Hadson Power 14 – Buena Vista,* 4 E.A.D. 258, 288-90 (E.A.B. 1992). This was the first application of that particular control technology to that particular unit in this country. *Id.* The permit in *Hadson Power* allowed the state agency to revise the emission limit downward toward the design limit after operation commenced to reflect an emission rate that the facility demonstrated was consistently achievable. *Id.* at 291. Similarly, EAB upheld an adjustable BACT emission limit for particulate matter with a diameter of ten microns or less (“PM10”) that allowed the permitting authority to adjust the initial limit upward if the facility was unable to meet it due to certain conditions. *AES Puerto Rico L.P.,* 8 E.A.D. at 347. Both of these cases show that a BACT emission limit can change over time, and thus provide support for IDEM’s CO_2 emission limit, (Draft Permit, condition D.4.9), although as explained below, the record in this case shows that more can be done here to limit potential future CO_2 emissions.

As an initial matter, CATF agrees with IG’s conservative explanation that the “combination of technologies and the operational constraints required for the technologies…are new and complex” and that the “experience on lifetime operations for a plant of this scale is limited.” Application, Appx. F at 2-8. Based on these circumstances, an allowance for some CO_2 venting at the AGR is warranted. Just as surely, however, IG will learn over time how to best optimize the operation of the Project to capture and sell CO_2 from it. For example, the coordination of maintenance outages across the facility and with downstream CO_2 customers is likely to improve with experience. So, too, should knowledge of the operation of such other key equipment as CO_2 compressors.

We recognize that IG views CO_2 as a sales product of the Project, and thus has incentives to minimize the vented volume of CO_2 in order to maximize the CO_2 sales volume. The record therefore supports an additional CO_2 emission limit to be effective beginning in the eighth operational year at a level equal to the actual CO_2 emissions in operational years four, five and six, plus a small margin (for example, ten percent of that average) for uncertainty unless IG demonstrates to the satisfaction of IDEM that special and unique circumstances during this averaging period make it unlikely that a new limit would be achievable in practice in subsequent years. This adaptable limit would be imposed based on the actual operations of the facility, expressed in tons of CO_2 emitted per unit SNG produced, *see* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at p.46 (March 2011) ("EPA encourages permitting authorities to consider establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation"), and must not be higher than the 1.29 million tpy that begins in the third year of plant operation. Such an adjustable, declining CO_2 emission limit is more protective of the environment than the limit in the Draft Permit, is consistent with the interests of IG and the State of Indiana, and is supported under relevant law and practice, and by the facts present here.

Response 8: It is standard practice under PSD to establish in the pre-construction permit a fixed BACT emission limitation, based on the best technical information available at the time of permit issuance. That BACT limitation applies to the operation of that emission unit until that unit later makes a change that triggers another PSD review. Occasionally, a permitting authority may devise a flexible approach to BACT emission limitations, but such an approach is not required and is the exception to the general rule. Based on the technical information available at this time (see for example Permit Application Appendix F on pages 3-2 and 3-3), IDEM has determined that the use of fixed BACT emission limitations for the AGR vents is appropriate. To the extent that additional technical information becomes available in the future, the PSD regulations provide opportunities for permit modifications at the request of the permittee or at the initiative of the permitting authority in appropriate situations. The best technical information available at those times would be used to inform any future BACT determination.

It should be noted that the CO_2 manufactured in the AGR is a valuable product, and the permittee has significant incentives to minimize the emission of CO_2 at the AGR vent. A permit condition that would change the limit based on operating history might be construed to encourage additional emissions from the AGR vent so as to preserve compliance headroom, would be inconsistent with the overall purpose of selling as much CO_2 as product as feasible, and is therefore also inappropriate.

Comment 9: The Act defines BACT as an *emission limitation* based on the *maximum degree of reduction* of each pollutant subject to regulation under this chapter *emitted from or which results from* any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

42 U.S.C. § 7479(3) (emphasis added). Importantly for present purposes, the plain text "which results from" in this provision defines both (a) "each pollutant" that must be reduced and (b) the object of the maximum degree of reduction requirement. In other words, the BACT limit must reflect the maximum degree of reduction of a pollutant covering both direct emissions onsite and emissions of the same pollutant that "result from" the facility. BACT thus does not allow a facility to supposedly reduce pollution, only for that pollution to be emitted to the atmosphere later down the road. Such a loophole would severely weaken the Act's stringent control requirements.

Ensuring that a permittee actually achieves the maximum degree of reduction is of particular concern with CO_2. CO_2 is widely distributed pollutant that produces impacts as a result of increasing global average concentrations of the gas in the atmosphere. Thus, imposing a constraint on the amount of CO_2 that may be released at one point without requiring a demonstration that the captured CO_2 is not simply being released at an off-site location would be ineffective as an method to reduce the harms to public health and welfare associated with the stream of emissions. It follows that, as taken up in more detail below, the BACT limit for CO_2 must contain conditions sufficient to demonstrate that captured CO_2 will be handled in a manner providing a high degree of assurance that the CO_2 will not be released to the air, either during transport of the CO_2 or from the location(s) to which it is transported.

Response 9: EPA's long-standing interpretation of the "which results from" language cited by the commenter does not require BACT analyses for off-site sources. To the extent that the off-site emissions to which the commenter refers should be considered "secondary emissions" at all under EPA's regulations and guidance, such emissions are also not subject to BACT. EPA's March 2011 PSD and Title V Permitting Guidance for Greenhouse Gases has this to say about the consideration of secondary emissions in a BACT analysis: "EPA has historically interpreted the BACT requirement to be *inapplicable to secondary emission*s, which are defined to include emissions that may occur as a result of the construction or operation of a major stationary source but *do not come from the source itself*." GHG Guidance at 24 (emphases added). The 1990 NSR Workshop Manual, further, states: "Secondary emissions are not considered in the potential emissions accounting procedure. . . . Secondary emissions occur from any facility that is not a part of the source being reviewed, but which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification." 1990 Manual at A.16.

In this case, the "source being reviewed" is the collection of emission units within the fence-line of the Indiana Gasification facility. EPA's guidance is plain that emissions from off-site sources—even if they would not have occurred but for the construction of the Indiana Gasification facility—are *not* included in the BACT analysis. *See also* 40 C.F.R. § 52.21(b)(18) (definition of "secondary emissions") ("Secondary emissions means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself."). EPA's Environmental Appeals Board has consistently focused the attention of permitting authorities on the stationary source itself: "As the Board has explained many times, BACT is a 'site-specific determination and * * * the combined results of the considerations that form the BACT analysis are the selection of an emission limitation and a control technology that are *specific to a particular facility*.'" *In re: Mississippi Lime Co.*, PSD App. No. 11-01, 2011 WL 3557194 at Section VI.A (Envtl. App. Bd. Aug. 9, 2011) (emphasis added). In the context of an attempt to include vessel emissions as a part of the BACT analysis at an Outer Continental Shelf facility, the EAB observed—quoting the very statutory language cited by NRDC in its comment here—that the permit challengers "fail to acknowledge that the statutory BACT definition does not address emissions disconnected from the emissions' source, but instead directs that the emissions limitation is established, on a 'case-by-case basis,' by determining what is 'achievable *for the facility'* through 'application' of various control methods." *In re: Shell Gulf of Mexico, Inc.*, OCS Appeal No. 10-01 at Section VI.A (Envtl. App. Bd. Dec. 30, 2010) (emphasis added). The BACT analysis does not include air pollution sources not at the facility under review.

The PSD program does, however, assess the impacts of secondary emissions on NAAQS and PSD increments in the ambient air quality impacts analysis. 1990 Manual at C.1. However, because there is no NAAQS or PSD increment for GHGs, EPA has directed that secondary emissions of CO_2 need not be included in the ambient air quality impacts analysis. *See* GHG Guidance at 47–48. Secondary emissions of CO_2 have no place in a review of the proposed facility.

Consequently, comments that relate to the control of CO_2 downstream of the proposed facility (*e.g.*, control of CO_2 during transportation, storage, use, and re-use in EOR operations) are not relevant to this permitting action.

Comment 10: IDEM's alleged GHG BACT determination is procedurally flawed.

As an initial matter, we note significant concern that the agency's supposed GHG BACT determination for the AGR Vent consists of a verbatim cut-and-paste of the applicant's (exceedingly thin) BACT analysis submitted in its application. *Compare* TSD Appendix B – "BACT Analyses" at 150-153 (concluding that sequestration is not technically feasible under BACT Step 2) and Application Appendix F at 3-3 to 3-8. Indeed, it appears that the agency simply substituted "IDEM" for "IG," absurdly leading it to conclude that the agency itself "cannot even begin the process of trying to engineer or build [pipeline infrastructure]." TSD Appendix B at 153 of 181. This blatant failure to conduct an independent assessment of the application and come to its own determination flies in the face of the agency's BACT duties. *See supra* at 3-5. For this reason alone, IDEM cannot move forward on the proposed permit without first doing the required analysis, coming to its own conclusion, and going through another public comment period.

In addition, the agency errs in even this thin attempt to apply the top-down analysis. IDEM provides an exceedingly short list of "potential control technologies" at Step 1 that inexplicably fails to even list use of captured CO_2 for EOR – relied upon later in selecting the proposed CO_2 BACT limit on the AGR vents themselves. Nor does IDEM determine whether sequestration of the AGR Vent CO_2 is an "available" technology under Step 1, but mis-categorizes this inquiry as a Step 2 question. *See* TSD Appendix B at 150; EPA GHG BACT Guidance at 33-34 (discussing availability of CCS as a Step 1 inquiry). It then punts on the availability question in general by claiming that sequestration is "technically infeasible" for this project under Step 2. To correct these errors, IDEM must include a complete list of the available control technologies and determine on the record whether it believes sequestration is available or not as a Step 1 matter. It must then make its own independent determination whether sequestration is, or is not, technically infeasible.

Not only does IDEM omit use of captured CO_2 for EOR as a control technology in Step 1, but it then discusses in Step 4 potential constraints on the project's ability to control CO_2 via EOR based on uncertainty around construction of the pipeline for EOR shipments of

CO_2. Assuming for argument's sake that these considerations are properly Step 4 factors, and that they go to issues particular to the startup of the facility, IDEM once again failed entirely to evaluate whether these separate BACT limits represent the maximum degree of reduction in CO_2 over the first two years of the facility's operation. It instead simply adopted the applicant's discussion and numbers without question.

Response 10: ***Independent review.*** It is the permit applicant's responsibility to prepare a complete and thorough application, including a detailed BACT analysis. The alternative—a situation in which state permitting agencies are required to prepare detailed supporting documents, including a BACT analysis—would result in complete paralysis of the state's permitting program. The permitting record contains approximately eighty documents that demonstrate arm's length communications between IDEM and the permit applicant, prompted in many cases by the agency's challenges to aspects of the original permit application and detailed responses. The fact that after this significant transparent and iterative process the final documents offered by the permittee in support of the application were sufficiently thorough that the permitting authority's decision was predicated on them does not show a lack of analysis or independence, but rather the opposite. The permitting authority pressed the permittee to ensure a robust permit application and supporting analysis; this is precisely what the permitting authority was required to do.

EOR omitted from top-down analysis. Enhanced oil recovery was not in Step 1 because this is a case of a product sale not regulated under the Clean Air Act. In addition, EPA has not even identified EOR as "available" for purposes of BACT if a party was not selling a product but attempting to comply with an emissions standard. It is important to distinguish between high-purity CO_2 produced by the AGR and delivered to the pipeline, and the high-purity CO_2 produced by the AGR but routed to the AGR vent. As explained on page one of the TSD, CO_2 produced by the AGR, compressed, and delivered to the pipeline is a *product* of the Indiana Gasification facility. That the delivered CO_2 has value as a product is evident by the fact that revenues from CO_2 sales are shared with ratepayers under the IFA contract, *see* Indiana Finance Authority contract Section 5.4(c), and the IURC considered the sale of CO_2 as a product as an important commercial term for the project. IURC Nov. 22, 2011, Order at 94 (commenting on allocation of "profits on the sale of CO_2"). As a product, that CO_2 is not an "air pollutant" as that term is defined by the Clean Air Act, and therefore no BACT analysis is required for the product CO_2. Conversely, CO_2 produced by the AGR that is vented is an "air pollutant" as that term is defined by the Clean Air Act, and for which a BACT determination is required. The CO_2 from the AGR vent—along with all other GHG emissions from the facility—are the GHGs for which a BACT determination was made.

By way of analogy, the AGR vented CO_2 is similar to gasoline fumes that may be emitted from a gasoline storage tank at a refinery. Had the gasoline been delivered for sale, it would be a product. Only because the gasoline was emitted into the ambient air did it lose its identity as a product, and become air pollution to which the Clean Air Act would apply. By way of further analogy, once delivered as a product to the fence line of the proposed facility, subsequent potential emissions of the product CO_2 are not the responsibility of the permit applicant any more than a carbonated beverage manufacturer is responsible for the ultimate release of CO_2 when the beverage container is opened. Or similarly, refineries producing gasoline as a product are not responsible for the air emissions from automobile refueling or the combustion of the gasoline in automobiles. The Clean Air Act places compliance obligations on the emitter of air pollution, not the manufacturer of products that may later through their use result in air pollution.

Sequestration excluded from list of available technologies. The commenter is mistaken in asserting that sequestration for AGR vent CO_2 was excluded from the list of available technologies in Step 1 of the top-down approach. For CO_2 emitted from the AGR vent, the BACT analysis explicitly included carbon sequestration in Step 1 of the top-down analysis. *See* TSD BACT Analysis at page 150. And while the TSD BACT Analysis does challenge in Step 2 EPA's assertion that CCS is "available," the TSD BACT Analysis very clearly states "this analysis will presume sequestration to meet the criteria as an 'available' technology." *Id.*

Sequestration properly excluded under Step 2. The commenter's suggestion that IDEM failed to address the question of availability is erroneous. The TSD BACT Analysis very clearly listed sequestration of AGR vent CO_2 as an "available" technology, and then in detail explained why the technology is nevertheless technically infeasible. *See* TSD BACT Analysis at 150–153.

Comment 11: IDEM erroneously eliminated sequestration as technically infeasible.

The analysis of sequestration that IDEM copied from the applicant is cursory at best, and erroneously concludes that this option is infeasible. In addition, IDEM relies on factors that are questionably legitimate Step 2 inquiries.

First, as to availability in Step 1, a number of successful sequestration projects are, and have been, operating successfully worldwide at full commercial scale. These projects have clearly demonstrated the availability of sequestration as a technology.

With respect to technical feasibility, IDEM concludes that "[t]he source has neither access to, nor can develop, a suitable sequestration site for the volume of CO2 that may be vented from the AGR vents" *See* TSD Appendix B at 151 of 181. IDEM further asserts that "[w]hile sequestration is being studied for use in the region where the plant will be located, there is presently no practical option" (*Id.*) and that the results of the nearby sequestration project by Archer Daniels Midland (ADM) in collaboration with the Midwest Geological Sequestration Consortium ("MGSC") will not be known for some time. These conclusions are in error.

The work that has been carried out by the MGSC and its partners for the purposes of the ADM sequestration project in Decatur is of particular relevance to the Indiana Gasification plant. This project is currently injecting carbon dioxide underground. Schlumberger Carbon Services ("Schlumberger") produced a sequestration feasibility study for Tenaska evaluating in significant detail the possibility of sequestration of captured CO2 at the nearby Mt. Simon sandstone formation in Illinois, for a site that is approximately 200 miles away from the proposed Rockport site. That analysis considered all of the appropriate technical feasibility issues such as geologic suitability of the Mt. Simon sandstone, injection well plume modeling, seismic data, etc., and concluded that use of the site was entirely feasible for the Facility:

> A geological study was completed to develop an assessment of the suitability of the site for storage of carbon dioxide. The work is the first phase in developing a geologic carbon dioxide (CO_2) storage site in the Mt. Simon formation. The goal of the study was to evaluate:
>
> 1. Whether the site has capacity to store the expected volume of CO_2 from the plant;
> 2. Containment of the storage reservoir;
> 3. Infrastructure requirements for storage (number and dimensions of injection wells, operational strategies)
>
> The results of the study indicate that the Mt. Simon sandstone has sufficient porosity (open space between the sand grains in the rock) and permeability (the degree to which the pore spaces are interconnected, allowing fluid to move through the rocks) and therefore provides a storage reservoir target capable of

accommodating all of the CO_2 produced by the plant over a planned operational life of 30 years. The Eau Claire formation, which overlies the Mt. Simon sandstone, will provide the vertical containment needed to prevent movement of CO_2 out of the Mt. Simon formation and into shallower geologic formations, ground water, and the atmosphere. There are also several other low permeability layers that provide secondary containment. The Mt. Simon formation and the containment layers are laterally extensive and available information, including the results of a subsurface (seismic) survey, confirm that there are no faults or breaks in the lateral continuity.

The Schlumberger Cost Study further concludes:

The geologic setting is favorable. The target formation of the Mt. Simon is estimated to be very thick at 1100-1300 feet with a high estimated porosity and permeability in the area selected. The thickness combined with the porosity and permeability allows for a high capacity injection field to be developed using a minimal number of wells. The field is estimated to only require 3 to 4 wells with a well spacing of only 2 miles. The thickness also reduces the area required for the CO_2 resulting in reduced right of way. Also, the target area is under and adjacent to the plant resulting in minimal pipeline cost.

None of this specific technical information was even referenced, much less considered, in IDEM's rejection of CCS as technically infeasible.

The overwhelmingly positive results from a nearby site should be considered evidence that sequestration may be technically feasible for Indiana Gasification as well. At the very least, they demonstrate the complete lack of diligence on Indiana Gasification's and IDEM's part in analyzing with any credibility whether sequestration is indeed feasible. The Schlumberger study highlights a number of the factors that have to be considered before opining on its technical feasibility. We see no evidence of such an examination in this case. Moreover, the worked carried out by MGSC and its partners could be directly applicable to Indiana Gasification if they decided to transport CO_2 to Illinois: the geology near Decatur has been extensively studied and characterized, which amounts to taking away the most significant source of uncertainty regarding the feasibility of sequestration. IDEM's assertion that the results from the ADM project will not be known for years is both misleading and false: even though monitoring will need to take place during the course of that project, no formal "verdict" is expected. There is considerable certainty already about the feasibility of the injection and the safety of the storage. At the very least, the wealth of current knowledge and data should lead IDEM to require further analysis of sequestration as a feasible option.

IDEM goes on to argue that logistical challenges related to the acquisition of rights of way for a CO_2 pipeline render sequestration technically infeasible. *See* TSD Appendix B at 153 of 181. This argument is wholly inadequate. Indiana Gasification would only need to follow the same steps as any other company (including Enhanced Oil Recovery companies) to build a pipeline. These steps are well defined and have been followed routinely for decades by all parties wishing to construct pipelines. Tardiness in beginning such a process cannot be used as an argument against the technical feasibility, especially when the construction of a pipeline by a third party is used as an option to transport CO_2 away from the plant site.

Finally, the ongoing nature of sequestration research sponsored by the U.S. Department of Energy (DOE), as well as any uncertainty surrounding the fate of other government sponsored sequestration projects (such as FutureGen 2.0) cannot be used as an argument against the technical feasibility of sequestration (*See* TSD Appendix B at 152 of 181): research efforts are indeed ongoing but are part of a long term program and not necessarily indicative of the feasibility of sequestration, and project uncertainty could be due to an assortment of logistical or other reasons. Only a detailed, site-specific analysis can be used to examine the technical feasibility of sequestration.

Response 11: The commenter questions the determination that sequestration is technically infeasible as BACT for CO_2 emissions from the AGR vent. Accordingly, this response will address that comment. The technical infeasibility of capturing CO_2 from other emission sources at the proposed facility was addressed thoroughly in the TSD BACT Analysis at pages 148, 156, 158, 167, 169, 171, 174, 176, and 177. These sources will not be addressed further.

The commenter points out several activities related to the research and development of sequestration. One of those is addressed on Page 151 of the BACT determination. The work underway by the MGSC was considered as a part of the AGR vent GHG BACT analysis for the Indiana Gasification project. The BACT determination indicates that MGSC was beginning a large-scale CO_2 injection project (1 million tons) over a three year period, but concludes that this Department of Energy funded demonstration project has not proven that sequestration is a technically feasible option for Indiana Gasification today.

The commenter's inclusion of the Schlumberger materials, which have been reviewed, does not change this conclusion. The commenter's claim that sequestration of CO_2 from the AGR is feasible in light of these recent studies is incorrect for three reasons.

First, the studies referenced by the commenter include a preliminary feasibility analysis of sequestration at the proposed Taylorville Energy Center. The Schlumberger studies were conducted on behalf of a proposed IGCC plant in Illinois, which IDEM understands does not have a CO_2 BACT limit as part of its State of Illinois issued air permit. The study describes its objectives as follows:

A geological study was completed to develop an assessment of the suitability of the site for storage of carbon dioxide. The work is the first phase in developing a geologic carbon dioxide (CO_2) storage site in the Mt. Simon formation. The goal of the study was to evaluate:

1. Whether the site has capacity to store the expected volume of CO_2 from the plant;
2. Containment of the storage reservoir;
3. Infrastructure requirements for storage (number and dimensions of injection wells, operational strategies).

(NRDC Exhibit 1, pg. 1). The Schlumberger studies concluded that the nearby Mt. Simon sandstone had sufficient porosity and permeability to provide a storage reservoir potentially capable of accommodating all of the CO_2 produced by the Taylorville Energy Center over a planned operational life of 30 years. That study, however, is not evidence of the current technical feasibility of sequestration at the Taylorville site, but is simply an initial estimate of the potential suitability of the site for possible future sequestration development. While the study does characterize the geology of this location in Illinois and indicates that the geology appears suitable for geologic sequestration based on seismic data and modeling analysis, these results do not render geologic sequestration technically feasible for Indiana Gasification. Importantly, the study itself indicates that its work is the "first phase" in developing a storage site. The study does not include drilling of injection wells or actual injection of $CO_{2.}$ Moreover, the cost study indicates the following uncertainty:

It should also be noted the estimate was completed without a test well.
When the first injection well is drilled, *actual conditions are likely to vary*

> *from those assumptions and could therefore result in the need for alternate designs, additional infrastructure, and revised operating assumptions*.

(NRDC Exhibit 2, pg. 1).

The Schlumberger feasibility study does not indicate that geologic sequestration is technically feasible; it only indicates the geologic conditions appear to be favorable.

Second, the first phase activity at the Taylorville facility can most fairly be described as a pilot test. As of February 2012, the MGSC Decatur demonstration project had injected about 70,000 tons of CO_2, and plans to continue to inject CO_2 for up to three years. The amount injected to date represents an amount equal to about six percent of the potential annual volumes from the Indiana Gasification AGR vent. During the MGSC demonstration project, measurement, monitoring and verification activities will be ongoing to evaluate how the injection proceeds, where the underground CO_2 plume forms, and whether permanent storage has been accomplished. The results of these evaluations are not known today. Importantly, Chuck McConnell, Chief Operating Officer for the U.S. Department of Energy (DOE) Office of Fossil Energy (FE) is quoted as saying:

> “This *injection test project* by MGSC, as well as those undertaken by other FE regional partnerships, are helping confirm the great potential and viability of permanent geologic storage as an important option in climate change mitigation strategies.”

(http://sequestration.org/resources/topStories.html accessed February 9, 2012) (emphasis added).

It is hoped that these demonstration test projects are developing important scientific data and understanding, but that understanding does not exist at a level that makes geologic sequestration technically feasible today. This position is further confirmed by a statement on the MGSC website regarding its mission:

> While the industrial processes required to make carbon sequestration possible have been known for quite some time, they have never been applied at the scale required to significantly reduce the atmospheric build-up of CO_2. Our challenge is to show the value of these technologies within our region, using geological resources *to demonstrate* that carbon dioxide can be stored safely and economically, deep underground.

(http://sequestration.org/challenge/index.html, accessed February 9, 2012) (emphasis added)

MGSC and the other DOE-funded regional partnerships are in the process of *demonstrating* geologic sequestration technologies. They have not completed their work. The work to date does not verify that geologic sequestration is technically feasible today at the scale that Indiana Gasification would need to sequester.

EPA’s October 1990 Draft PSD Workshop Manual says that in the context of a technical feasibility review, “technologies in the pilot scale testing stages of development would not be considered available for BACT review.” Workshop Manual at B.17. In the case of Taylorville, the facility is not even testing a technology, but is examining whether a facility is even appropriate for the installation of a technology. But even if the Taylorville facility is considered to be testing a “technology,” because the Taylorville facility is in the “test” or “demonstration” mode, it cannot be considered an “available” technology for purposes of a BACT review.

Third, Illinois EPA has decided that sequestration was not technically feasible for the Taylorville facility (though a final permit has not yet been issued). EPA's recent PSD and Title V Permitting Guidance for Greenhouse Gases notes that it is important for permitting authorities to pay "particular attention to the most recent information from the commercial sector and other recently-issued permits." Office of Air Quality Planning and Standards, U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 35 (March 2011) ("EPA GHG Guidance"). The PSD permit application for the Taylorville Energy Center was submitted in April 2010. The draft permit was noticed for public comment on October 17, 2011. In the summary accompanying the draft permit, IEPA explained "[a]lthough the results of [the Schlumberger studies] were favorable, many other technical issues associated with geologic CO_2 sequestration still need to be resolved. In addition, there are unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration. Further development of sequestration is needed before a BACT emission limit could be set for the proposed plant that is predicated upon implementation of CCS."

The public comment period on the draft Taylorville Energy Center PSD permit closed on December 30, 2011. In their comments on the draft permit, some parties have asserted that IEPA's finding that CCS is technically infeasible at the Taylorville Energy Center is in conflict with the Schlumberger studies. As detailed above, the Schlumberger studies do not establish technical feasibility of CCS at the Taylorville facility. In addition, some commenters have asserted that IEPA's finding is in conflict with Christian County Generation's application for a Class VI geologic sequestration permit from EPA under the Safe Drinking Water Act's Underground Injection Control program, submitted in September 2011. Christian County Generation's application for a Class VI UIC permit merely reflects its intention to sequester CO_2 in the future, however, and does not conflict with IEPA's finding that geologic sequestration is *currently* technically infeasible.

EPA, in its comments, requested that the project summary be updated to reflect the fact that Christian County Generation applied for a Class VI geologic sequestration permit. EPA did not conclude, however, that sequestration was feasible for the project but, instead, requested that IEPA revisit this determination in light of Christian County Generation's Class VI permit application.

In sum, because the Schlumberger studies do not point to the present availability of the Taylorville site to accept millions of tons of CO_2 from the Indiana Gasification facility, because the Taylorville site is still in a pilot or demonstration phase, and because IEPA has concluded that sequestration is not technically feasible at the Taylorville site, the assessment of sequestration as presented in the BACT determination remains valid.

Comment 12: The proposed limit fails to ensure the maximum degree of reduction achievable.

IDEM failed by omitting any requirement that the facility demonstrate that the captured CO_2 emissions will not re-enter the atmosphere. Without such a demonstration, the emission limitation does not reflect the maximum degree of reduction in greenhouse gases resulting from the facility and the permit does not ensure compliance with the BACT limit. *See supra*,2-6. Due to its composition as a compressed gas, the potential for release of captured CO_2 is extremely high unless specific steps are taken to ensure that it will not escape from pipelines or other means of transport and will not escape from the site(s) to which it is delivered. Accordingly, a permit provision that simply measures releases from on-site CO_2 vents and ignores the fate of the captured CO_2 that is diverted to a location past the fenceline clearly would not meet the statutory definition of "emission limitation" because it would not be effective in limiting the amount of captured CO_2 that was emitted to the air or resulted from the facility. Such a permit structure would allow the captured CO_2 to be released at any time and any point. For example, captured CO_2

could be piped to facility that used the CO_2 to make carbonated beverages, resulting in only a slight delay in the release of this pollutant. Similarly, a permit authorizing a system that sends captured CO_2 to an enhanced oil recovery operation cannot be recognized as establishing an emission limitation for CO_2 unless the enhanced oil recovery facility is required to operate pursuant to an approved regime that demonstrates permanent retention of the injected CO_2. Thus, the permit for any source that captures CO_2 must require a demonstration that the captured CO_2 is delivered to a facility that is subject to design and operational requirements adequate to assure the permanent isolation of the delivered CO_2 from the atmosphere.

Current federal and state regulations for pipelines and enhanced oil recovery sites do not provide any assurance that CO_2 from the source will not be vented to the atmosphere or that any leaks will be remedied or quantified. Underground injection of carbon dioxide (CO_2) is regulated under EPA's Underground Injection Control Program (UIC). The UIC rules have been promulgated under the authority of the Safe Drinking Water Act (with the exception of Class I hazardous wells which implement RCRA requirements) in order to protect Underground Sources of Drinking Water (USDWs).

Under UIC, injection is permitted through wells or area permits. There are six injection well classes, two of which are most relevant to commercial scale CO_2 injection: Class VI and Class II. Class II dates back several decades and is used for injecting brines, CO_2 and other fluids associated with oil and gas production, and hydrocarbons for storage. This would almost certainly be the class under which Indiana Gasification's CO_2 offtakers would operate. Class VI is a new injection well class, which applies to wells that inject CO_2 for geologic sequestration. Class VI rules were proposed by EPA in July, 2008 and were promulgated in December, 2010, specifically the purpose of CO_2 sequestration.

Regulatory requirements for Class VI are more comprehensive than for Class II on many counts:

- The information than needs to be submitted at the time of a permit application is more extensive under Class VI.
- Class VI siting requirements include an injection zone with sufficient properties to receive the total anticipated volume of CO_2 injectate, a confining zone big enough to contain injected and displaced fluids, and with sufficient integrity to allow injection without initiating or propagating fractures. Class II only requires a confining zone that is free of transmissive faults and fractures.
- Monitoring requirements for Class II are limited to analyzing injected fluids with sufficient frequency to yield data representative of its chemical and physical characteristics, as well as injection rate, pressure and volume measurements. Class VI requirements include an extensive testing and monitoring plan that covers operational parameters for the well, direct and indirect methods to track the extent of the CO_2 plume and the area of elevated pressure, water quality measurements, as well as surface monitoring if required by the Director.
- Class requirements for a well plugging plan are tailored to individual situations rather than requiring off-the-shelf methods to be used.
- Class II lacks any post-injection site care and site closure requirements. Class VI requires post-injection monitoring for fifty years, or an alternative period if it can be shown that it is sufficient, in order to establish the evolution of the injected CO_2 and displaced fluids, and that no USDWs are being endangered. Once no endangerment established, then the Director may authorize site closure, at which point financial responsibility obligations cease.
- The area of review and corrective action requirements for Class VI are broader. The actual area of review does not rely on default distances, needs to be updated at least every five years, requires modeling of certain specifications to determine the extent of the CO_2 plume and displaced fluids, and more extensive

identification of penetrations within the area of review. A revision of the area of review also may require revision of other required plans.

- Financial responsibility obligations under Class VI go further than Class II.
- Class VI emergency and remedial response provisions require actions by the owner or operator to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. Class II has no such requirements.
- Construction requirements, as well as requirements for logging, sampling and testing, go further in Class VI than they do in Class II.
- The standard for granting primacy to states for the implementation of the program is weaker for Class II wells, and consists of a general effectiveness demonstration as opposed to meeting individual stringency and adequacy criteria.

Although Class VI requirements have been promulgated with the express purpose of protecting USDWs and not necessarily ensuring the safe and effective sequestration of CO_2 and preventing any releases to the atmosphere, they go a long way towards doing so. This is because of the site characterization and screening requirements, the need to establish and maintain a confinement zone, and act when confinement is breached. However, select cases such as well blowouts or vents directly to the atmosphere, or areas without USDWs may not be covered.

EPA’s regulations do not require all CO_2 injection sites to be permitted as Class VI wells. Only owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. The Director must consider a number of relevant factors when making such a determination. However, there is no definition or “primary purpose”, and guidance is pending regarding the transition from Class II to Class VI. This loophole allows EOR projects that wish to demonstrate sequestration to remain in Class II rather than transition to Class VI.

In terms or reporting any leaks, the Clean Air Act (CAA) provides EPA with the authority to require data reporting that will inform and are relevant to EPA’s implementation of a wide variety of CAA provisions. Subpart RR of the reporting rule applies to wells that inject a CO_2 stream for long-term containment in subsurface geologic formations. Subpart UU applies to wells that inject a CO_2 stream into the subsurface (without the objective of long-term containment.

Under subpart RR (which, alongside subpart UU was promulgated in December, 2011), there is no reporting threshold, and basic mass flows of CO2 received, produced, leaked and sequestered must be reported. In addition, a Monitoring, Reporting and Verification (MRV) plan is required to be submitted by the owner/operator that includes:

a. Identification of CO_2 leakage pathways in MMA, incl. likelihood, magnitude and timing, and
b. Delineation of the monitoring area
c. A strategy for detecting and quantifying any surface leakage of CO_2
d. A strategy for establishing expected baselines for monitoring CO_2 surface leakage

There are no specific requirements for these actions and strategies analogous to the Class VI requirements. MRV plans are reviewed on an individual basis. Subpart UU requires reporting only of the mass of CO_2 received, and does not require any MRV.

All Class VI wells must report under subpart RR, but Class II wells must report under subpart UU and may choose to report under subpart RR. Therefore, it is at the discretion of an EOR operator whether to conduct *any* MRV needed to demonstrate sequestration and whether to quantify and report any leakage. This is wholly inadequate for the purposes of demonstrating that CO_2 from Indiana Gasification's facility has not eventually been vented. Even if operators voluntarily report under subpart RR, there is no guarantee that the scope of the MRV will be adequate. Worse none of the reporting rule subparts require any mitigation in the event of leakage – they simply require that the leakage be estimated and reported.

Thus, the permit for any source that captures CO_2 must require a demonstration that the captured CO_2 is delivered to a facility subject to design, maintenance and operational requirements adequate to assure the permanent isolation of the delivered CO_2 from the atmosphere. EPA's current regulatory infrastructure as it applies to Enhanced Oil Recovery operations is not adequate in ensuring the non-emission of transported and injected CO_2, nor does is require quantification and reporting of any such leaks.

IDEM may structure such a requirement by, at a minimum, mandating that the applicant submit as part of its permit application a CO_2 plan under which the applicant certifies that the entities to which it transfers captured CO_2 are subject to a regulatory program that requires them to follow design, operational and maintenance requirements sufficient to assure permanent isolation of the CO_2 from the atmosphere. This could be achieved if enhanced oil recovery operations took place under UIC Class VI and subpart RR CAA reporting requirements. The plan must be made part of the initial permit record and subject to public comment; thus, IDEM must renotice the proposed permit for public comment once the applicant submits the CO_2 plan.

In advance of comprehensive regulations from EPA that ensure the permanent sequestration of CO_2 during enhanced oil recovery, a CO_2 plan that does not rely on Class VI regulation under UIC should contain but not be limited to the following:

- A demonstration that sites are capable of long-term containment of carbon dioxide;
- Identification and characterization of potential natural and man-made leakage pathways, and appropriate risk management and corrective actions;
- Design, construction and operation parameters to prevent, mitigate and remediate the creation or activation of leakage pathways, or and the migration of CO_2 or fluids into any zone in a manner not authorized by the Administrator (or pursuant to a State program approved by the Administrator as meeting the requirements of this section);
- Minimizing fugitive CO_2 emissions from project operations;
- Monitoring and modeling to predict and confirm the position and behavior of the CO_2 and other fluids in the subsurface during and after injection;
- Accounting and reporting of CO_2 quantities sequestered, injected, recycled, leaked, vented, and any other categories as appropriate; and,
- Post-injection site closure and financial responsibility requirements that ensure the long-term containment of injected CO_2.

Response 12: The commenter suggests that the entire regulatory program for managing the transportation, storage, and injection of CO_2 in geologic formations and any consequent "leakage" of CO_2 must be analyzed in the proposed facility's BACT analysis. See Response to Public Comment 9 for a description of the emissions that must be considered in the BACT analysis. As discussed in Response to Public Comment 10, which includes a description of the CO_2 sources that must be analyzed for BACT purposes, secondary emissions (if any) associated with CO_2 delivered as product are not air emissions associated with this facility, and therefore not subject to BACT.

Consequently, the commenter's detailed discussion of preventing CO_2 from entering the air from EOR use of CO_2 is not relevant to this permit proceeding.

Comment 13: Higher carbon dioxide emissions for two years should not be allowed, use the lower limit from the start of the permit.

Response 13: See Response to Public Comment 8.

Comment 14: Indiana is one of the worst states for CO_2 emissions.

Response 14: Indiana's current economy is based on energy intensive industry and electrical power generation. This leads to relatively high CO_2 emissions at the state level. Indiana regulates CO_2 emissions from all new plants that emit large amounts of CO_2 through the Prevent of Significant Deterioration (PSD) program.

This permitting action deals with a new source and this new source is subject to a PSD review and the application of Best Achievable Control Technology (BACT) requirements for greenhouse gases, including CO_2. The GHG BACT Analysis for this source is set out in Appendix B-BACT Analyses, to the Technical Support Document.

Comment 15: What happens if the pipeline isn't built?

Response 15: See Response to Public Comment 7.

Comment 16: CO_2 sequestration is too costly and dangerous. Will this CO_2 be sequestered?

Response 16: The permitting authority has concluded that geologic sequestration of emitted CO_2 is technically infeasible for this project, and has accordingly not required CO_2 sequestration.

Hazardous Air Pollutants (HAPs) Comments:

Comment 17: **The Permit Must Provide Practically Enforceable Conditions Restricting the Project from Being a Major Source of HAP Emissions.**

Review of the File shows the Draft Permit is premised upon the Project not being a major source of hazardous air pollutant (HAP) emissions.

File review shows the Project has an unrestricted PTE for a single HAP (methanol) of greater than 10 tons/year and an unrestricted PTE for all HAPs of greater than 25 tons/year. Specifically, Appendix A: Emissions Calculations Emission Summary (Uncontrolled Potential to Emit) shows the combined Potential to Emit for all emission sources totals 17.98 tons/year methanol and 53.26 tons/year Total HAPs. Therefore, the Project would be a major source subject to additional requirements, unless there are sufficient practically enforceable permit restrictions in the Permit to limit the HAP emissions to less than 10 tons/year methanol and 25 tons/year Total HAP.

The Draft Permit apparently intends to limit methanol emissions such that the Project is not a major source (i.e., it would be an "area source" as defined in 40 CFR 63.2; sometimes referred to as a "minor source"). Appendix A: Emissions Calculations Emission Summary shows the Limited Potential to Emit for emission sources totals 9.66 tons/year methanol and 24.79 tons/year Total HAPs. However, the restrictions to achieve the limited Potential to Emit are insufficient. The Commenter believes the Permit can appropriately restrict HAP emissions to less than 10 tons/year methanol and 25 tons/year Total HAP by addressing the comments below.

Review of Appendix A data summaries shows the following emission units whose PTE either of methanol emissions or Total HAP emissions are limited in some fashion (i.e., emission units with no reduction of HAP emissions are not included):

	Uncontrolled PTE (tons/year)		**Limited PTE (tons/year)**	
Emission Unit	**Methanol**	**Total HAPs**	**Methanol**	**Total HAPs**
Auxiliary Boiler (005A/B)	0	6.69	0	1.4
Acid Gas Recovery Unit (007A/B)	10.54	37.83	9	22.5
Gasifier Preheat Burners (008A-E)	0	0.75	0	0.1
Fugitive Emissions	7.15	7.58	0.38	0.38

The Commenter reviewed the Draft Permit for requirements that practically limit the emission of HAP such that the source would be an area source.

Review of the Draft Permit shows Condition D.6.9 Operational Limit practically restricts the Auxiliary Boiler (005A/B) emissions via a fuel throughput restriction. However, it is not clear from the face of the permit whether this restriction is a necessary requirement for restricting HAP emissions to create an area source. If the fuel throughput restriction has as part of its purpose the limitation of HAP emissions, IDEM should, clarify that purpose in an Addendum to the TSD and add clarification to Condition D.6.9 as follows (new text italicized): “The total throughput of fuel to the two (2) natural gas-fired auxiliary boilers, identified as EU-005A/B, shall not exceed a total firing rate of 1430 billion Btu per twelve (12) consecutive month period, with compliance determined at the end of each month. *Compliance with the above limit and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.*”

Response 17: As stated above the two (2) natural gas-fired auxiliary boilers were limited to a total firing rate of 1430 billion Btu per twelve (12) consecutive month period, which is part of the process to limit all the emissions from the boilers including the HAPs emissions. The above statement from the commenter has been included in new Condition D.6.9 - Hazardous Air Pollutants (HAPs) Minor Limits of the permit.

D.6.9 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAP from the natural gas-fired auxiliary boilers identified as EU-005A and EU-005B shall be limited by compliance with Condition D.6.10 - Operational Limit and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

Comment 18: Draft Permit Condition D.4.11 Hazardous Air Pollutants (HAPs) Minor Limits expressly limits HAP emission from the Acid Gas Recovery Unit (007A/B) for the purpose of making the source an area source of HAPs. Therefore, the relevance of the restriction with respect to area source status is clearly set forth. With regard to these emission units (007A/B), it is noted that the File record (i.e., Draft Permit and TSD documents) is not consistent in describing what the Commenter has presumed are the same emission units. For example, the emission unit description in Draft Permit D.4(E) describes Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B; Conditions D.4.5, D.4.7, D.4.18 and D.4.19 use the D.4(E) description. However, Conditions D.4.8 and D.4.11 describe Acid Gas Recovery Unit vents (EU-007A/B), Conditions D.4.9 describes both Acid Gas Recovery (AGR) vents and Acid Gas Removal (AGR/RTO) Unit vents, and Condition D.4.10 describes AGR units. Other such differences may appear elsewhere in the Draft Permit and TSD. IDEM should clarify whether these descriptions are the same or different emission units. Additionally, the Permit should reflect editing such that it uses consistent emission unit descriptions.

Response 18: IDEM has revised the emission unit description for the two (2) Acid Gas Removal (AGR) Unit vents, as EU-007A and EU-007B to be consistent as set forth by the file record throughout the permit. IDEM conducted a BACT analysis for the regenerative thermal oxidizer controlling the AGR which is the AGR/RTO. This is the identification for the AGR regenerative thermal oxidizer not the identification for the AGR itself. As stated above the identification for the AGR Unit vents are EU-007A and EU-007B.

Comment 19: The Commenter was not able to determine the mechanism (e.g., a restriction on fuel usage, hours of operation, or something else) that restricts HAP emissions from Gasifier Preheat Burners (008A-E). However, it may be practically achieved via the CO_2 emissions limit in Condition D.7.8 GHGs PSD BACT [326 IAC 2-2-3]. IDEM should, at a minimum, clarify in an Addendum to the TSD the requirement(s) by which HAP emissions for these units are limited for the purpose of area source status. For clarity, IDEM should add the following to Permit Condition D.7.8: "*Compliance with the above limit and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.*"

Response 19: While the commenter is correct that the CO_2 emissions limit operates as a practical limitation on overall HAPs, because uncontrolled HAPs PTE from the pre-heat burners would not result in overall HAPs PTE exceeding the major source thresholds, no HAPs limitation is necessary for the preheat burners.

In addition, the HAPs emissions from the preheat burners are very small but the source will be restricting their fuel usage to comply with the CO_2 emission limit, which will have the effect of restricting the HAPs emissions. Condition D.7.12(a) - Record Keeping and Requirement clearly specifies that the source shall maintain monthly records of the type and amount of fuel combusted in the Gasifier Preheat Burners.

Comment 20: Control of Fugitive Emissions is a significant element in limiting HAP emissions. Draft Permit Section D.15 and Condition E.6.1 CO, H2SO4, SO2, and GHG PSD BACT [326 IAC 2-2-3] establish Leak Detection and Repair (LDAR) requirements; however, it is not clear that LDAR requirements are established to limit source HAP emissions such that the source is an area source for HAP emissions. The basis for Project HAP fugitive emissions is included in TSD Appendix A. The TSD data shows fugitive emissions are controlled by applying published reduction factors achieved via implementation of an LDAR program. IDEM should specifically clarify, in both the Permit and an Addendum to the TSD, that implementation of an LDAR program is one of the requirements for achieving area source status. For clarity, IDEM should add the following to Permit Condition D.15.4:

"*Compliance with the LDAR program incorporated in Section E.6 for equipment in methanol service and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.*"

Response 20: IDEM has included the above language in a new Condition D.15.5 - Hazardous Air Pollutants (HAPs) Minor Limits to clarify that, the implementation of an LDAR program is one of the requirements for achieving area source status for this source.

D.15.5 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAPs from the Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation identified as FUG & FUG-WSA shall be limited by compliance with the LDAR program incorporated in Section E.6 for equipment in methanol service and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

BACT Analysis Comments:

Comment 21: Sections D.7.4 and D. 6.4 show that particulate emissions from burning the same amount of the same fuel are about 10 ½ times more from the large, 408 MMBtu/hr boilers as from the much smaller 35MMBtu/hr burners. The larger should be held to a lower not a larger amount, as it should be possible for larger combustion to be more cleanly accomplished and emissions from it controlled more thoroughly than from the smaller combustions. Why are the larger combustors allowed to produce more emissions per unit of heat?

Response 22: Particulate emissions from any clean gas fired source are very small. Particulate emissions from the Auxiliary Boilers have been estimating using the standard EPA AP42 emissions factors for particulate emissions from natural gas combustion (permit condition D.6.4). This is the standard methodology for conventional external combustion sources. The particulate emissions for the unique gasifier preheat burners (permit condition D.7.4) include the additional consideration that the combustion exhaust from these preheat burners pass through the gasifier quench water system which is expected to remove a significant amount of the already low particulate emissions. An explanation of the selection of these emissions factors is presented in IG's application on page 3-4.

LDAR Comments:

Comment 22: **LDAR Comments:**

The LDAR provisions in Condition E.6.1 are ambiguous and should be revised.

Draft Permit Condition E.6.1 states, in part that:

> The source is not a major source of HAPs and is not subject to any of the MACT standards under 40 CFR Part 63. However, in the context of the BACT determination for this source, **the substantive requirements** of 40 CFR 63 Subpart H, addressing equipment leaks, apply to the **components** listed under 40 CFR 63.160(a) that are in service at the facility for the following **process**

streams: methanol streams, propylene streams, and product SNG streams. The same Subpart H requirements apply to any leaks of SO_2 in the Wet Sulfuric Acid unit piping between the combustor and oxidation reactor, beginning with the connector at the combustor and ending with the connector at the oxidation reactor, except that references in the regulations to methane or VOCs will instead be applied to the pollutant SO_2.

The condition's reference to the "substantive requirements" is ambiguous. If only the requirements of Subpart H identified throughout E.6.1 are deemed the substantive portions, then the condition should be modified to clearly state those are the substantive requirements. If it means all of Subpart H except specific requirements, IDEM should specify those that are excepted. If it means interpreting Subpart H requirements with different definitions, then those definitions should be specified in E.6.1.

LDAR implementation can be challenging to even the most experienced professionals. Lack of clarity and consistency in terminology would further complicate compliance efforts. For example, Subpart H regulates leaks from "equipment" (as that term is defined in 40 CFR 63.161); it does not specify requirements in terms of "components" (as referenced in E.6.1). Under Subpart H, regulated equipment must be "in organic hazardous air pollutant service" (as that term is defined in 40 CFR 63.161). Unless the Project propylene and product SNG streams contain 5 percent by weight of organic HAP they would not qualify as streams "in organic hazardous air pollutant service" under Subpart H; thereby creating uncertainty as to what requirements are intended by E.6.1. Therefore, it is unclear what practically enforceable requirements E.6.1 actually creates for the process streams listed. If IDEM intends the Permittee to only implement particular Subpart H requirements, then the Permit needs to be more specific. Accordingly, for the purpose of applicability and compliance with Subpart H requirements under Condition E.6.1, it should appropriately specify those substances (e.g., VOC, HAP, SO_2, etc.) that are to be considered as if they were organic hazardous air pollutants (OHAP).

Regardless of the approach developed to incorporate LDAR requirements, the Permit should clearly specify whether the requirements are necessary with respect to limiting HAP emissions to area source thresholds. In addition, LDAR compliance obligations should be clear, complete, and practically enforceable.

Response 22: The applicable permit conditions are being edited to clarify the role of LDAR in limiting HAP emissions and the components to which these requirements apply. The following edits are being implemented to condition E.6.1.

E.6.1 CO, H2SO4, SO2, and GHG PSD BACT [326 IAC 2-2-3] **and Hazardous Air Pollutants (HAPs) Minor Limits**

The source is not a major source of HAPs and is not subject to any of the MACT standards under 40 CFR Part 63. However, in the context of the BACT determination for this source **and the limitation of HAP emissions**, the requirements of 40 CFR 63 Subpart H, addressing equipment leaks, **that are listed below, apply to the pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, instrumentation systems, and control devices or systems** that are in service at the facility for the following process streams: methanol streams, propylene streams, and product SNG streams. The same Subpart H requirements apply to any leaks of SO_2 in the Wet Sulfuric Acid unit piping between the combustor and oxidation reactor, beginning with the connector at the combustor and ending with the connector at the oxidation reactor, except that references in the regulations to methane or VOCs will instead be applied to the pollutant SO_2. **These requirements apply to the above listed streams irrespective of the HAP content of the specified streams.**

……

Comment 23: What about leaks in pipes caused by acidic waste streams?

Response 23: The LDAR provisions of this permit are applicable to appropriate piping and components with the potential to leak air pollution. As such, leaks of any origin will be detected and addressed through maintenance and repair requirements of the permit. It should be noted that sulfuric acid is used commonly in manufacturing and there is extensive experience in the specification of metallurgy and the selection of materials for components and piping that are resistant to acid corrosion.

Compliance Assurance Monitoring (CAM) Comments (Testing, CEMs and Monitoring)

Comment 24: Section A.3 (c) - Specifically Regulated Insignificant Activities calls four rod mill operations insignificant and indicates no emissions controls will be required. These would be mills that crush coal. There will be coal dust made and apparently vented to the atmosphere. I call this significant activity. What justifies not requiring pollution controls on this operation?

Response 24: All emissions units in Section A.3 are specifically regulated insignificant activities in accordance with 326 IAC 2-7-1(21). The four (4) rod mills, identified as EU-013A through EU-013D have low emissions because they are a wet process in which a high volume of water is mixed with the coal/coke feedstock at the inlet of the rod mill and the combined mixture ground into a high solids aqueous slurry. This aqueous slurry is then fed to the slurry holding tanks from which it is pumped into the gasifiers. Because the rod mill coal grinding occurs in an aqueous solution, even without add-on controls, the rod mill particulate emissions are extremely small (e.g.; 0.1 lb/hr and 0.44 tons/yr PM10). Accordingly, the rod mill vents are considered an insignificant activity in accordance with 326 IAC 2-7-1(21)(B) because the uncontrolled emission of PM10 is less than five pounds per hour or twenty-five pounds per day. The classifications of these emission units in this draft permit are strictly related to air pollution emissions.

Comment 25: Section D.1.4 (a) (1) controls $PM_{2.5}$ via a baghouse, which filters allow a great percentage of uncontrolled $PM_{2.5}$ to be emitted. What justifies use of less than the maximally effective (this is *not* MACT and please do not confuse it with MACT or BACT) pollution controls of PM and $PM_{2.5}$?

Response 25: A baghouse (also known as a fabric filter) does provide the greatest level of control for PM, PM_{10} and $PM_{2.5}$. IDEM conducted a top-down BACT analysis of PM, PM_{10}, and $PM_{2.5}$ control technologies as part of its review and included it as Appendix B to the Technical Support Document. This source has no condensable PM emissions, and, in this review, IDEM concluded that the same control technologies were applicable to all three forms of PM. The control technologies evaluated included a wet scrubber, wet suppression, a cyclone and a fabric filter. IDEM made a final determination that a fabric filter was the top ranked control technology for all three forms of PM (PM, PM_{10} and $PM_{2.5}$) and that BACT for the emission units under evaluation was a fabric filter achieving a maximum loading from the control device of 0.003 grains per dry standard cubic foot (dscf) for PM and PM_{10} and 0.0015 grains per dry standard cubic foot (dscf) for $PM_{2.5}$. This level of control is more stringent than any BACT limit reviewed for permits for other sources with similar emission units. Therefore, the baghouse control devices provide the highest effective control for PM, PM_{10}, and $PM_{2.5}$.

Comment 26: Section D. 1.6 (d) allows operation, when temperature is below 32 degrees with no suppression of coal dust Particulate Matter. It is not specified if this is 32 degrees Celsius, which, if it is, would mean no suppression most of the time, i.e., when air temperature is below approximately 89 degrees Fahrenheit. Why does this oversight exist and how will you correct it; which 32 degrees is it?

Response 26: The temperature is in Fahrenheit. IDEM has made the appropriate clarification in Condition D.1.6 - PM, PM_{10} and $PM_{2.5}$ Control in the permit accordingly. See response to Sierra Club Comment 69.

Comment 27: Section D. 1.7 (a) allows excessive time to perform tests. Testing should be done at or shortly after operation inception, not up to 180 days after, as the permit allows. What justifies not requiring testing sooner after operations begin?

Section D. 5.16 (b) allows up to 365 days to expire following start up of operations for testing to be performed and results filed with IDEM. This is far too long a period. What justifies allowing this much time to elapse and what will the emissions be during this period?

Response 27: Section D.1.7 (a) applies to the testing of the emissions of the baghouse on the feedstock conveying systems. While the operator is given 180 days to demonstrate the emissions levels through testing, the obligation to install, operate and maintain the baghouse applies from initial operation of the conveying system. See Section D.1.5 and D.1.6. The 180 days are provided to allow time to develop and submit a test protocol, line up a testing contractor and achieve a condition representative of normal operation. Earlier testing might represent conditions not representative of normal loading on the control system. Section D.5.16 applies to the demonstration of particulate emissions from the Wet Sulfuric Acid unit. The timing of that test is also keyed to the startup of gasifiers to ensure that there will be representative throughput in the WSA at the time of test. As with the feed stock conveyor baghouse, the timing of the testing does not alter the obligation to start up and operate the units with emissions controls functioning correctly. In summary, IDEM believes all permit terms and conditions are correct and require sufficient testing to ensure compliance.

Some sources need time to build up a supply of raw materials to be able to run emission units at representative conditions. If the source cannot operate at a representative capacity, the test may not be considered valid and must be repeated as production increases. If the test is not completed within the time allotted, IDEM may initiate an enforcement action.

Because this large facility has many interrelated operations, full load and representative operating conditions on some units cannot be achieved until multiple upstream units are operating, which may take up to 365 days to occur. Therefore, IDEM determined it was appropriate to extend the testing of some of the emission units to 365 days after start up of the first gasifier unit. No revisions to the draft permit are required as a result of this comment.

Comment 28: The syn gas flare is extremely dirty for its fuel consumption. Can the emissions from the flare be controlled?

Response 28: The project incorporates a number of measures to reduce emissions from the syngas flare and those measures are reflected in operational and emissions limits in the permit. First, the flare pilot will operate on clean natural gas or SNG. Second, the gasifiers will be started on a clean feedstock, methanol, so that the gasified material going to the flare during startup will have negligible SO2. Also, during gasifier shutdowns, most of the residual gas in the gasifier will be sent to downstream treatment systems and only a small residual will be sent to the flare. IDEM conducted a top-down BACT analysis for flare emissions, which is included in the TSD, that provides an evaluation of potentially available control technologies.

Comment 29: Section D.6.13 specifies that only one test of CO emissions will take place and that can be up to 180 days after startup. Conditions at a facility change over time and emissions can change with those. This testing is inadequate to protect the public. Will these test results be used as a surrogate for other emissions? If so, what justifies such use? If the test is to measure combustion efficiency, what justifies only one test, as combustion characteristics change over time?

Response 29: The two (2) natural gas-fired auxiliary boilers have no add-on control device for CO emissions, and the CO combustion characteristics are inherent in the design of the burners. Therefore, the CO emissions from the natural gas-fired auxiliary boilers are expected to remain essentially the same throughout the life time of the emission unit. The one time testing will be performed to verify compliance with the CO BACT limit given to the source. However, IDEM may require compliance testing at any specific time when necessary to determine if these facilities are in compliance. If testing is required by IDEM, compliance shall be determined by a performance test conducted in accordance with Section C - Performance Testing. No revisions to the draft permit are required as a result of this comment.

Comment 30: Inspections (Compliance monitoring): IDEM inspections are rare and will be with this plant. Maybe IDEM will inspect once per year, what happens the rest of the time?

Response 30: See Response to Public Comment 50.

Potential to Emit Comments:

Comment 31: What are the PTEs for dioxins/furans of individual combustors and gasifiers proposed to be operated at this site? Why are dioxins/furans not listed in the PTE lists in this permit? What justifies not listing them?

Response 31: The combustion of natural gas, SNG, syngas and diesel fuel do not produce dioxin/furans. Dioxin/furans are associated with the direct combustion of more complex organic materials such as coal and plastics. With regard to natural gas used in the boilers and preheaters, and diesel fuel used in the emergency engines, EPA emissions factors for HAPs from these fuels list no dioxins or furans. The SNG combusts in the same manner as natural gas and has no dioxins or furans or their precursors. With regard to the syngas, according to the United States Department of Energy, dioxin and furan compounds are not expected to be present in the syngas from gasification systems for two reasons. First, the high temperatures in the gasification process effectively destroy any dioxin/furan compounds or precursors in the coal or coke feed. Second, the lack of oxygen in the reduced gas environment would preclude the formation of the free chlorine from HCl, thus limiting chlorination of any dioxin/furan precursors. If the syngas is combusted, one would not expect formation of dioxin/furan compounds because very little of the particulate matter required for post combustion formation is present in the clean syngas or in the downstream combustion gases. Measurements of dioxin/furan compounds in existing gasification systems confirm these expectations. (Source: A Comparison of Gasification and Incineration of Hazardous Wastes Final Report, March 30, 2000, (http://www.netl.doe.gov/publications/others/techrpts/igcc_wp.pdf).

Comment 32: This permit is based upon the EPA's AP-42, Compilation of Air Emission Factors, demonstrated by the material in the support documents. The introduction to AP-42 clearly states that emission factors contained in it are not reliably accurate for a specific source.

(EPA, January 1995, “Introduction to AP-42, Volume 1, Fifth Edition, January 1995, pp.2,3). The EPA clearly indicates that their PM 10 factor does not, in this permit application, include condensable PM. (ibid, p6, paragraph 2). The PM 10 PTE in this permit is most likely to be inaccurate. How much condensable PM will this facility’s individual components emit and what are the health and environmental dangers of these condensable PM emissions?

This permit fails to specify if the PM amounts include or do not include condensable particulate matter, a significant form of pollution. Condensable must be included in an accurate listing of emissions and appears not to be. What justifies not listing PTEs of condensable particulate matter in this permit?

Response 32: Because there is no separate applicability threshold for the condensable fraction of particulate, IDEM is not required to separately list out the PTE for this subset of total particulate. However, in its review of emissions estimates, IDEM has considered condensable particulate for all emission sources for which condensable particulate is expected, as discussed below.

The largest particulate emission sources at the facility are the Wet Sulfuric Acid (WSA) units. The particulate from the WSA units is primarily sulfuric acid mist, which is presumed to be a condensable particulate formed from acid which starts out as a gas and then condenses. The emissions estimate for these WSA emissions is based on information provided by the WSA process licenser.

Particulate emission from combustion sources (e.g.; auxiliary boiler, preheat burners, flares, AGR vent, etc.) are based on AP-42 factors for natural gas combustion, which include both filterable and condensable particulate.

Particulate emissions from non-contact cooling towers are expected to result only from dissolved solids in the cooling water, in which is considered filterable particulate. Particulate emissions from this source are estimated using AP-42 specified methodology.

Particulate emissions from the ZLD spray dryer, ASU Regeneration Vents, and Emergency Engines are based on vendor estimates which include, if applicable, condensable particulate.

Plant haul road dust is all filterable particulate. There fugitive emissions are not exhausted at an elevated temperature, so there is no condensable particulate associated with roadway dust. The filterable particulate is estimated using the appropriate AP-42 methodology.

Likewise, the particulate matter emissions from the Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles, day bins, and other feedstock handling steps are all filterable PM; there are no condensable PM emissions from these units.

IDEM believes that the Permittee has adequately documented the source of the emission factors used in the calculations submitted.

Comment 33: Section D.6.15 is based upon emission factors without specifying where those are from. Most likely, they are AP-42 factors; the emissions figures stand a two out of three chance of being incorrect and the degree of their inaccuracy cannot be determined. Where are these factors from, and what is their degree of inaccuracy?

Response 33: Permit condition D.6.15 is the permit condition limiting total CO_2 emission from the Auxiliary Boilers. The CO_2 emissions factor specified (116.89 lb CO2/MMBtu) is taken from the methodology in US EPA's 2009 Greenhouse Gas Mandatory Report Rule 40 CFR Part 98, Subpart C – General Stationary Fuel Combustion Sources. Specifically, it is the factor in that Subpart in Table C-1 (Default CO_2 Emissions factors and High Heat Values for Various Types of Fuels) for "Natural Gas, Pipeline (weighted U.S average)" which is 53.02 kg CO_2/MMBtu (converted to lbs./MMBtu). This value is similar to, but about ½% lower than the older AP42 factor for CO_2 from natural gas external combustion in AP42 Chapter 1.4 (most recent update was July 1998). The factor specified is provided for use by all facilities for this type of source in EPA's Mandatory GHG Reporting Rule and is considered to be appropriate for use in permitting.

Comment 34: AP-42 clearly states the degree of inaccuracy cannot be determined: "Because insufficient data exist to determine the accuracy or validity of the emission factors...no estimates can be made of the error that results from using these factors to calculate toxic air emissions from any given facility." (Pope, Anne A., et al, October 1990, EPA-450/2-90-011, Toxic Air Pollutant Emission Factors- A Compilation for Selected Air Toxic Compounds and Sources, Second Edition, [AP42], p. 7; and, with the exception of the words, "in this compilation," in document EPA-450/2-91-028, EPA, 1991, Crosswalk [XATEF] Air Toxic Emission Factor Data Base Management System User's Manual, Version 1.2, p. 7)

Response 34: The permit contains enforceable limits on the operation of sources and the emissions of sources that serve as the controlled potential to emit ("PTE") for those units. For information related to the use of emission factors, see Responses to Public Comment 42 and Sierra Club Comments 29, 33, and 36.

Comment 35: Section D. 2.7 requires calculation of emissions using an emissions factor; the EPA states factors do not accurately indicate actual emissions. How inaccurate, expressed in a percentage of the calculated quantity, will these calculations be?

Response 35: Because this emission unit is subject to BACT, the emission limits imposed are based upon the maximum degree of pollution reduction that is achievable on a case-by-case basis. Part of the BACT process for developing emission limits involves reviewing the limits imposed at other similar sources in order to determine whether the proposed limits are at least as stringent as those being met at other facilities. In part because this BACT review requires comparison to other facilities, both the methods used to develop the limits and the resulting limits are comparable to what is used at other facilities. The techniques used to estimate emissions are consistent with standard practice for this type of source and consistent with the compliance methodology commonly utilized by comparable facilities, and are therefore considered to be accurate and appropriate for the source.

The NOx and CO emissions factors specified for the flare are design specifications from the equipment vendor. The particulate emissions factors are based on AP-42 Chapter 1.4 for natural gas combustion, which although small, are actually larger than those provided in the AP-42 section for industrial flares (Chapter 13.5), which lists particulate (soot) emissions from non-smoking flares as zero (0). A detailed explanation of the basis of the SO_2 emission factor for the hydrocarbon flare is provided in the response to Sierra Club Comment 44.

Environmental Justice Comment:

Comment 36: Environmental Justice Comment:

(a) Rockport, a community of slightly greater than 2,000 people has Toxic Releases from two existing industries on the edge of town that measure more than thirty million pounds of releases each year. That is more toxic releases than the combined total of the industrial (TRI reported) emissions of Atlanta, New York City, Pittsburgh, Philadelphia, Indianapolis, Chicago, Seattle, Los Angeles and San Diego COMBINED (representing a combined population of 34 million people).

As a result, the area is impoverished, having an average per capita income that is only about 2/3 of the national average. Sadly it also translates into higher levels of cancer, respiratory, and cardio vascular death and disease than the rest of the United States.

Valley Watch has followed the issue of environmental justice due to this problem for years and we assert that it is precisely places like Rockport that Plan EJ 2014 was designed to ameliorate. However, IDEM, in issuing this draft permit has completely ignored the issue in direct contradiction of the current protocol.

(b) Environmental Justice. This area has more pollution that several major cities but Rockport has only 2,000 people, but IDEM doesn't care. EJ is not mentioned in the permit.

Response 36: IDEM is committed to its Environmental Justice Policy, which can be viewed at http://www.in.gov/idem/files/A-008-OEA-08-P-R2.pdf on IDEM's website.

Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, geographic location or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The Policy requires that IDEM ensure all members of the public have: (1) equal access to public information pertinent to Agency policies and procedures; (2) adequate notice regarding all Agency program information and decision-making processes; and (3) the opportunity to provide public comments and pertinent information to Agency program staff.

IDEM has followed this Policy throughout the permitting process. IDEM published a notice of this permitting action in the local newspaper. IDEM also posted a copy of the draft permit on its website and provided a copy to the local library. On January 25, 2012, IDEM held a public meeting and a public hearing at the South Spencer High School Auditorium in Rockport, IN, for citizens and interested parties to discuss questions and concerns related to the project.

Furthermore, the proposed facility is not located in an "area of concern" for environmental justice issues. Using 2000 U.S. Census data, IDEM has created a map to identify potential areas of environmental justice concern in Indiana based on racial minority, Hispanic/Latino minority, and income. Rockport, IN, and the downwind areas are not among them. The proposed project, therefore, will not have disproportionately high and adverse environmental effects on minority and/or low income populations.

As the relevant permitting agency, IDEM's environmental justice policy applies in this instance. Nevertheless, Valley Watch cites to recent U.S. EPA guidance designed to increase U.S. EPA's efforts to address environmental justice concerns. In 1994, President

Clinton issued Executive Order (EO) 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" directing all federal agencies to participate in a government-wide effort to address environmental justice issues. EO 12898 also established an Interagency Working Group to assist the covered agencies by providing guidance and serving as a clearinghouse.

More recently, in August 2011, the covered federal agencies signed a "Memorandum of Understanding on Environmental Justice and Executive Order 12898." The purposes of this memorandum were to (1) declare the continued importance of identifying and addressing environmental justice considerations, (2) renew the process under EO 12898 for agencies to provide environmental justice strategies and implementation progress reports, (3) establish structures and procedures to ensure that the Interagency Working Group operates effectively and efficiently, and (4) identify particular areas of focus to be included in agency environmental justice efforts. The memorandum of understanding requires, among other things, that each agency prepare an "Environmental Justice Strategy" to be posted on its public webpage.

Consistent with this mandate, U.S. EPA published "Plan EJ 2014" in September 2011. Plan EJ 2014 is a four-year roadmap to help U.S. EPA develop stronger community relationships and increase U.S. EPA's efforts to improve environmental and health conditions in overburdened communities. Plan EJ 2014 is not a rule or regulation, but instead a strategy to help integrate environmental justice in U.S. EPA's day-to-day activities.

With regard to public participation, IDEM complied with several of the recommended best practices in the Plan EJ 2014 Guidance, including:

- Public notifications outside of newspapers
- Direct and targeted outreach to community organizations and institutions
- Making documents physically accessible and free to communities
- Scheduling meetings during non-working hours
- Permit process descriptions of when, where, and how the public can get involved

See U.S. EPA, "Plan EJ 2014: Considering Environmental Justice in Permitting," at 10-11 (September 2011). U.S. EPA's Plan EJ 2014 guidance regarding public participation, therefore, overlaps with and is consistent with IDEM's Environmental Justice Policy, which was followed throughout the permitting process.

Comment 37: Meetings on permit should be held when elderly are more likely to attend, at mid day, at a more centrally located site.

Response 37: IDEM held a public meeting and a public hearing at the South Spencer High School Auditorium in Rockport, IN, on January 25, 2012. The public meeting began at 5:30 p.m., during which IDEM staff made an opening statement and took questions and comments regarding the permits for the construction and operation of the proposed state-of-the-art SNG and liquefied CO_2 production plant. At 6:30 p.m., IDEM conducted a formal public hearing on the draft permits. Citizens had the opportunity to submit written comments and make formal statements concerning the draft permits during that time.

IDEM held the public meeting and hearing during non-working hours to maximize attendance. Indeed, holding meetings during non-working hours is recommended by U.S. EPA in its environmental justice guidance. See U.S. EPA, "Plan EJ 2014: Considering Environmental Justice in Permitting," at 10-11 (September 2011). Although IDEM scheduled a meeting during non-working hours to maximize attendance, those unable to attend the meeting were permitted to submit written comments on the draft permits.

Finally, the South Spencer High School Auditorium is located in Rockport, IN, and therefore an appropriate location for the public meeting and hearing.

National Ambient Air Quality Standard Comment:

Comment 38: The Clean Air Act requires that new major sources of pollutants demonstrate that they will not cause or contribute to a violation of any ambient air quality standards. The current ambient air quality for ozone is 75 ppb. For example there are no ozone monitors in Spencer County, we do not know how severe our problem is. Since pollution has no boundaries, we know of several neighboring counties already near or above the acceptable amount of 75 ppb. For example, in 2011 a new monitor in Knox County at the Southwest Purdue Agricultural Center registered 77 ppb, Perry County monitor registered 74 ppb, Posey County monitor registered 76 ppb, Warrick County Boonville High School 75 ppb and Evansville 77 ppb.

On page 37 of IDEM's technical support document, IDEM admits it did conduct a computer modeling analysis of the levels of fine particulate matter that would be released when the facility is built and that the additional particulate matter would be in violation of the National Ambient Air Quality Standard for fine particulate matter.

Response 38: The following spreadsheets show ozone values in southwestern Indiana since 1995. Note that not all sites were operating until after that time. The National Ambient Air Quality Standard (NAAQS) for ozone for each monitoring location is the fourth highest daily value for a year, averaged over a three-year period. As shown in the righthand column (“3 year Average of 4th High”) in each table, all sites are currently in attainment of the 0.076 ppm (76 ppb) standard based on the ozone monitoring in the area.

It should also be noted that IDEM did not operate an ozone monitor in Knox County in 2011, nor does it now.

Southwest Indiana Region

EIGHT HOUR OZONE AVERAGES (PPM)

Greene County

	Year	1st	Date	2nd	Date	3rd	Date	4th	Date	Days => 0.085 ppm	3 Year Average of 4th High	
											3 Year Period	Site Design Value
	2000	0.095	6/1	0.093	6/9	0.091	6/8	**0.090**	5/31	4	(00 avg)	**0.090**
Plummer	2001	0.092	6/13	0.091	6/18	0.087	6/19	**0.085**	5/4	5	(00-01 avg)	**0.087**
18 055 0001	2002	0.097	8/10	0.095	7/8	0.095	9/8	**0.093**	7/15	14	(00-02 avg)	**0.089**
	2003	0.097	6/18	0.092	6/24	0.092	6/25	**0.088**	8/25	4	(01-03 avg)	**0.088**
	2004	0.076	4/16	0.075	4/29	0.075	9/23	**0.073**	8/19	0	(02-04 avg)	**0.084**
	2005	0.084	6/25	0.082	6/24	0.079	6/29	**0.079**	7/10	0	(03-05 avg)	**0.080**
	2006	0.081	6/17	0.077	8/25	0.076	6/6	**0.076**	6/16	0	(04-06 avg)	**0.076**
	2007	0.090	6/17	0.086	8/2	0.085	5/21	**0.084**	5/23	3	(05-07 avg)	**0.079**
										Days => 0.076 ppm		
	2008	0.075	4/23	0.075	7/18	0.072	4/22	**0.072**	7/16	0	(06-08 avg)	**0.077**
	2009	0.071	6/25	0.070	6/24	0.070	6/7	**0.068**	6/27	0	(07-09 avg)	**0.074**
	2010	0.076	4/12	0.075	4/13	0.074	5/5	**0.074**	4/14	1	(08-10 avg)	**0.071**
	2011	0.089	6/7	0.082	8/2	0.080	9/3	**0.080**	8/1	7	(09-11 avg)	**0.074**

Perry County

	Year	1st	Date	2nd	Date	3rd	Date	4th	Date	Days => 0.085 ppm	3 Year Average of 4th High	
											3 Year Period	Site Design Value
	2004	0.081	8/19	0.080	4/16	0.080	5/7	**0.078**	4/29	0	(04 avg)	**0.078**
Leopold	2005	0.088	7/10	0.086	6/30	0.086	8/1	**0.086**	8/11	4	(04-05 avg)	**0.082**
18 123 0009	2006	0.084	6/15	0.082	6/17	0.080	7/1	**0.079**	7/2	0	(04-06 avg)	**0.081**
	2007	0.092	9/20	0.086	7/25	0.085	8/15	**0.080**	9/22	3	(05-07 avg)	**0.081**
										Days => 0.076 ppm		
	2008	0.080	7/18	0.078	8/20	0.075	7/28	**0.073**	7/29	2	(06-08 avg)	**0.077**
	2009	0.076	6/25	0.067	6/2	0.067	6/1	**0.065**	6/6	1	(07-09 avg)	**0.072**
	2010	0.077	8/9	0.077	6/21	0.075	7/14	**0.072**	8/13	2	(08-10 avg)	**0.070**
	2011	0.080	6/6	0.079	6/9	0.076	9/1	**0.074**	7/11	3	(09-11 avg)	**0.070**

Posey County

	Year	1st	Date	2nd	Date	3rd	Date	4th	Date	Days => 0.085 ppm	3 Year Average of 4th High	
											3 Year Period	Site Design Value
	1996	0.061		0.059		0.057		**0.054**		0	(96 avg)	**0.054**
St Philips	1997	0.096	7/12	0.090	6/23	0.089	7/18	**0.087**	6/27	4	(96-97 avg)	**0.070**
18 129 0003	1998	0.111	9/13	0.096	8/17	0.095	9/12	**0.092**	5/14	11	(96-98 avg)	**0.077**
	1999	0.105	9/4	0.104	9/2	0.098	9/3	**0.096**	9/5	15	(97-99 avg)	**0.091**
	2000	0.093	8/29	0.086	7/9	0.086	7/27	**0.085**	6/8	5	(98-00 avg)	**0.091**
	2001	0.080	6/18	0.080	6/19	0.079	5/10	**0.079**	6/12	0	(99-01 avg)	**0.086**
	2002	0.106	8/3	0.099	8/9	0.098	9/8	**0.097**	6/20	13	(00-02 avg)	**0.087**
	2003	0.092	6/24	0.082	6/23	0.080	6/18	**0.077**	6/29	1	(01-03 avg)	**0.084**
	2004	0.077	9/23	0.073	4/16	0.073	6/30	**0.071**	8/18	0	(02-04 avg)	**0.081**
	2005	0.085	8/1	0.080	6/23	0.080	7/10	**0.077**	7/9	1	(03-05 avg)	**0.075**
	2006	0.079	7/19	0.066	6/15	0.063	7/18	**0.058**	6/16	0	(04-06 avg)	**0.068**
	2007	0.086	8/1	0.084	7/25	0.081	5/22	**0.080**	6/12	1	(05-07 avg)	**0.071**
										Days => 0.076 ppm		
	2008	0.080	4/23	0.073	8/20	0.070	7/17	**0.069**	7/16	1	(06-08 avg)	**0.069**
	2009	0.076	6/24	0.070	5/20	0.069	6/6	**0.067**	5/23	1	(07-09 avg)	**0.072**
	2010	0.072	8/7	0.071	9/20	0.071	8/19	**0.069**	9/21	0	(08-10 avg)	**0.068**
	2011	0.079	6/2	0.076	6/30	0.076	6/29	**0.076**	6/7	4	(09-11 avg)	**0.070**

***Site started 7-01-96**

Vanderburgh County											3 Year Average of 4th High	
	Year	**1st**	**Date**	**2nd**	**Date**	**3rd**	**Date**	**4th**	**Date**	**Days => 0.085ppm**	**3 Year Period**	**Site Design Value**
	1995	0.101		0.096		0.095		**0.094**		18	(95 avg)	**0.094**
Evansville - Mill Rd.	1996	0.100		0.097		0.092		**0.090**		8	(95-96 avg)	**0.092**
18 163 0012	1997	0.105	7/12	0.101	7/17	0.094	7/25	**0.093**	6/23	6	(95-97 avg)	**0.092**
	1998	0.111	9/13	0.102	9/12	0.099	5/14	**0.092**	5/18	8	(96-98 avg)	**0.091**
	1999	0.101	9/5	0.100	9/4	0.098	8/12	**0.098**	9/2	18	(97-99 avg)	**0.094**
	2000	0.085	8/29	0.083	7/9	0.083	7/27	**0.081**	8/17	1	(98-00 avg)	**0.090**
	2001	0.077	6/18	0.074	7/21	0.073	6/12	**0.073**	7/16	0	(99-01 avg)	**0.084**
	2002	0.105	8/13	0.102	7/8	0.096	8/9	**0.095**	7/15	16	(00-02 avg)	**0.083**
	2003	0.089	6/24	0.086	8/27	0.082	6/29	**0.081**	6/23	2	(01-03 avg)	**0.083**
	2004	0.078	9/23	0.074	6/30	0.073	4/16	**0.072**	8/18	0	(02-04 avg)	**0.082**
	2005	0.090	6/23	0.081	6/22	0.081	8/1	**0.080**	8/9	1	(03-05 avg)	**0.077**
	2006	0.092	7/19	0.083	7/18	0.079	8/17	**0.075**	6/9	1	(04-06 avg)	**0.075**
	2007	0.089	8/28	0.088	8/1	0.086	8/14	**0.085**	8/12	4	(05-07 avg)	**0.080**
										Days => 0.076 ppm		
	2008	0.083	7/16	0.079	7/17	0.074	7/18	**0.074**	5/29	2	(06-08 avg)	**0.078**
Evansville - Buena Vista	*2009	0.064	6/24	0.062	5/20	0.061	6/25	**0.061**	6/6	0	(07-09 avg)	**0.073**
18 163 0021	2010	0.067	6/25	0.067	6/3	0.064	6/21	**0.064**	5/29	0	(08-10 avg)	**0.066**
	2011	0.085	7/1	0.078	6/7	0.077	7/2	**0.077**	6/2	5	(09-11 avg)	**0.067**

***Site was moved to new location on 7/10/2009**

Vanderburgh County											3 Year Average of 4th High	
	Year	**1st**	**Date**	**2nd**	**Date**	**3rd**	**Date**	**4th**	**Date**	**Days => 0.085 ppm**	**3 Year Period**	**Site Design Value**
Inglefield	1995	0.099		0.097		0.096		**0.096**		20	(95 avg)	**0.096**
18 163 0013	1996	0.103		0.098		0.095		**0.094**		12	(95-96 avg)	**0.095**
	1997	0.105	7/12	0.102	7/17	0.093	7/18	**0.089**	7/7	8	(95-97 avg)	**0.093**
	1998	0.107	9/13	0.099	5/14	0.098	8/17	**0.094**	9/12	10	(96-98 avg)	**0.092**
	1999	0.098	6/21	0.095	9/4	0.094	9/5	**0.091**	9/2	9	(97-99 avg)	**0.091**
	2000	0.077	6/1	0.076	7/27	0.075	6/4	**0.075**	7/9	0	(98-00 avg)	**0.086**
	2001	0.079	6/12	0.076	6/18	0.073	5/10	**0.072**	5/4	0	(99-01 avg)	**0.079**
	2002	0.097	7/8	0.095	8/3	0.089	7/15	**0.086**	6/21	5	(00-02 avg)	**0.077**
	2003	0.085	6/24	0.081	6/23	0.075	6/29	**0.075**	7/17	1	(01-03 avg)	**0.077**
	2004	0.065	4/16	0.061	4/29	0.058	4/17	**0.058**	8/18	0	(02-04 avg)	**0.073**
	2005	0.058	7/10	0.057	6/23	0.056	5/7	**0.056**	5/18	0	(03-05 avg)	**0.063**
	2006	0.095	7/19	0.088	7/18	0.082	7/17	**0.081**	6/15	2	(04-06 avg)	**0.065**
	2007	0.091	8/28	0.089	8/14	0.088	6/17	**0.088**	7/25	8	(05-07 avg)	**0.075**
										Days => 0.076 ppm		
	2008	0.077	8/20	0.075	7/17	0.075	7/16	**0.072**	4/23	1	(06-08 avg)	**0.080**
	2009	0.076	6/24	0.069	6/6	0.069	5/20	**0.068**	6/27	1	(07-09 avg)	**0.076**
	2010	0.077	4/14	0.073	4/12	0.071	8/10	**0.071**	8/8	1	(08-10 avg)	**0.070**
	2011	0.080	6/7	0.074	7/7	0.073	6/30	**0.072**	9/3	1	(09-11 avg)	**0.070**

Warrick County											3 Year Average of 4th High	
	Year	**1st**	**Date**	**2nd**	**Date**	**3rd**	**Date**	**4th**	**Date**	**Days => 0.076 ppm**	**3 Year Period**	**Site Design Value**
	1995	0.104		0.089		0.088		**0.087**		7	(95 avg)	**0.087**
Yankeetown	1996	0.102		0.098		0.097		**0.093**		14	(95-96 avg)	**0.090**
18 173 0002	1997	0.095	8/1	0.094	7/18	0.091	7/12	**0.091**	8/2	7	(95-97 avg)	**0.090**
	1998	0.119	9/13	0.113	9/12	0.099	5/14	**0.096**	5/18	10	(96-98 avg)	**0.093**
	1999	0.101	9/5	0.098	9/4	0.096	6/22	**0.095**	8/12	5	(97-99 avg)	**0.094**
	2000	0.081	7/26	0.080	7/9	0.077	7/27	**0.077**	8/15	0	(98-00 avg)	**0.089**
	2001	0.087	6/12	0.082	6/18	0.081	6/19	**0.081**	9/13	1	(99-01 avg)	**0.084**
	2002	0.113	7/8	0.097	8/9	0.094	6/21	**0.094**	9/6	17	(00-02 avg)	**0.084**
	2003	0.101	6/24	0.090	7/17	0.082	6/7	**0.082**	8/27	2	(01-03 avg)	**0.085**
	2004	0.075	8/18	0.074	4/29	0.074	6/30	**0.074**	8/3	0	(02-04 avg)	**0.083**
			Site discontinued September 30, 2004									

Warrick County											3 Year Average of 4th High	
	Year	**1st**	**Date**	**2nd**	**Date**	**3rd**	**Date**	**4th**	**Date**	**Days => 0.085 ppm**	**3 Year Period**	**Site Design Value**
	1995	0.106		0.098		0.090		**0.090**		9	(95 avg)	**0.090**
Boonville	1996	0.094		0.093		0.090		**0.090**		10	(95-96 avg)	**0.090**
18 173 0008	1997	0.109	7/17	0.097	7/12	0.097	7/18	**0.095**	8/2	9	(95-97 avg)	**0.091**
	1998	0.114	9/13	0.105	9/12	0.100	8/22	**0.091**	5/13	9	(96-98 avg)	**0.092**
	1999	0.092	6/21	0.091	9/5	0.088	6/22	**0.087**	9/2	5	(97-99 avg)	**0.091**
	2000	0.078	6/1	0.075	7/27	0.074	6/9	**0.073**	6/8	0	(98-00 avg)	**0.083**
	2001	0.091	6/12	0.081	6/19	0.079	6/18	**0.078**	9/13	1	(99-01 avg)	**0.079**
	2002	0.107	7/8	0.093	9/6	0.092	6/21	**0.091**	7/16	13	(00-02 avg)	**0.080**
	2003	0.087	6/24	0.087	8/27	0.083	7/17	**0.076**	6/7	2	(01-03 avg)	**0.081**
	2004	0.084	8/3	0.076	6/30	0.075	8/18	**0.073**	4/29	0	(02-04 avg)	**0.080**
	2005	0.096	6/25	0.085	6/29	0.081	8/4	**0.080**	6/22	2	(03-05 avg)	**0.076**
	2006	0.087	7/19	0.086	7/18	0.083	8/17	**0.078**	7/17	2	(04-06 avg)	**0.077**
	2007	0.086	8/28	0.084	8/15	0.083	6/17	**0.083**	9/4	1	(05-07 avg)	**0.080**
										Days => 0.076 ppm		
	2008	0.073	8/20	0.072	7/29	0.072	7/16	**0.071**	7/18	0	(06-08 avg)	**0.077**
	2009	0.071	6/25	0.066	6/2	0.066	5/20	**0.064**	7/9	0	(07-09 avg)	**0.072**
	2010	0.077	8/2	0.076	8/8	0.072	4/13	**0.071**	6/3	2	(08-10 avg)	**0.068**
	2011	0.089	7/1	0.085	6/7	0.076	8/1	**0.075**	7/2	3	(09-11 avg)	**0.070**

Warrick County											3 Year Average of 4th High	
	Year	**1st**	**Date**	**2nd**	**Date**	**3rd**	**Date**	**4th**	**Date**	**Days => 0.085 ppm**	**3 Year Period**	**Site Design Value**
	2005	0.083	6/25	0.078	6/22	0.077	5/6	**0.077**	8/5	0	(2005 avg)	**0.077**
Dayville	2006	0.080	6/9	0.078	6/10	0.078	7/18	**0.078**	7/19	0	(05-06 avg)	**0.077**
18 173 0011	2007	0.078	6/13	0.078	8/28	0.077	6/16	**0.076**	6/12	0	(05-07 avg)	**0.077**
										Days => 0.076 ppm		
	2008	0.067	4/23	0.063	7/16	0.061	4/22	**0.060**	8/20	0	(06-08 avg)	**0.071**
	2009	0.068	6/27	0.059	7/9	0.059	6/29	**0.057**	8/14	0	(07-09 avg)	**0.064**
	2010	0.077	6/25	0.074	8/8	0.073	9/15	**0.070**	9/14	1	(08-10 avg)	**0.062**
	2011	0.079	6/7	0.077	7/1	0.074	6/2	**0.072**	6/6	2	(09-11 avg)	**0.066**

Warrick County											3 Year Average of 4th High	
	Year	1st	Date	2nd	Date	3rd	Date	4th	Date	Days => 0.085 ppm	3 Year Period	Site Design Value
	1995	0.108		0.107		0.096		0.093		10	(95 avg)	0.093
Lynnville	1996	0.103		0.102		0.095		0.094		8	(95-96 avg)	0.093
18 173 0009	1997	0.108	7/17	0.097	7/18	0.095	8/1	0.094	7/12	10	(95-97 avg)	0.093
	1998	0.109	9/13	0.098	9/12	0.095	8/17	0.093	8/21	9	(96-98 avg)	0.093
	1999	0.098	6/21	0.096	9/5	0.094	9/2	0.092	6/22	11	(97-99 avg)	0.093
	2000	0.080	6/1	0.079	6/8	0.078	7/27	0.077	6/9	0	(98-00 avg)	0.087
	2001	0.087	6/12	0.077	6/18	0.076	9/13	0.075	6/10	1	(99-01 avg)	0.081
	2002	0.094	9/6	0.091	6/21	0.091	7/15	0.090	7/16	12	(00-02 avg)	0.080
	2003	0.089	6/24	0.086	8/27	0.082	7/17	0.078	6/29	2	(01-03 avg)	0.081
	2004	0.070	4/16	0.066	4/29	0.066	8/18	0.066	9/23	0	(02-04 avg)	0.078
	2005	0.082	6/25	0.078	8/9	0.077	6/29	0.076	7/23	0	(03-05 avg)	0.073
	2006	0.076	6/9	0.074	7/19	0.074	8/17	0.070	6/17	0	(04-06 avg)	0.070
	2007	0.084	7/3	0.084	8/3	0.081	6/16	0.080	5/21	0	(05-07 avg)	0.075
										Days => 0.076 ppm		
	2008	0.076	8/20	0.068	4/23	0.064	9/24	0.064	7/29	1	(06-08 avg)	0.071
	2009	0.068	6/24	0.066	6/27	0.066	5/20	0.064	6/25	0	(07-09 avg)	0.069
	2010	0.073	8/8	0.070	8/13	0.070	8/9	0.070	4/13	0	(08-10 avg)	0.066
	2011	0.079	6/7	0.076	7/1	0.072	6/30	0.072	6/6	2	(09-11 avg)	0.068

Regarding particulate, IDEM performed a modeling analysis for $PM_{2.5}$ and showed IG is not culpable for any violations of the National Ambient Air Quality Standard (NAAQS). As explained in response to Sierra Club Comment 23, even though the model predicted a NAAQS violation, U.S. EPA guidance states that “the source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation.” U.S. EPA Workshop NSR Manual (Draft 1990) at C.52. Because IG was not significant at the same receptor and time period, it does not cause or contribute to a violation of the NAAQS. The analysis and results of the evaluation of $PM_{2.5}$ impacts can be found at pages 6-9 of 49 of the Air Quality Analysis for the permit.

Modeling Comments:

Comment 39: It should be noted that the region in the air shed of this plant is already saturated with a variety of air pollutants and just recently met the 1997 standards for ambient air quality for both fine particles and ozone, an improvement Valley Watch would contend did not occur as a result of any Federally enforceable action to reduce, but instead the air quality improvement that occurred resulted from the reduced level of economic activity that accompanied the serious recession experienced since 2007. That recession saw a reduction of electrical generation across the board of approximately 25% from the years 2007 through 2010.

Interestingly, monitored data in 2011, a time of increased economic activity, showed increased levels of air pollutants across the board as more electricity was generated in the area. In fact, had new ozone and fine particle standards been implemented as EPA’s Scientific Advisors had recommended, the region would have been found in non-attainment of the National Ambient Air Quality Standards for both ozone and fine particles if 2011 was the only year considered.

That is important since the pollution released from the Indiana Gasification proposal would have had to be offset if the region was considered non-attainment. Since the Cross State Air Pollution Rule has now been deferred by the US Court of Appeals and there is no real certainty as to its ultimate fate and thus the reliance of both IDEM and EPA that the area will remain in attainment and there is no way that it can call any of the provisions for pollution reductions “Federally Enforceable.”

IDEM failed to look at this possibility in issuing a permit in an area that is depending on significant reductions of fine particle precursors in making their designation of the region as an attainment area. As a result, the analysis on which the re-designation was made is seriously flawed. Therefore, it is questionable whether this permit should have been treated as a PSD permit instead of an NSR permit, requiring offsets from existing polluters in order to construct a new major source.

Further, IDEM chose not to include any modeling of this plant's impact on downwind ozone or fine particles to determine just how emissions from this plant would impact regions with chronic air pollution problem downwind both east and west.

Response 39: In July 2008, IDEM submitted a request for redesignation and a maintenance plan for fine particles for the Southwestern Indiana area.

The Southwestern Indiana area has attained the annual NAAQS for fine particles. IDEM prepared a State Implementation and Maintenance Plan that meets the requirement of Section 110(a)(1) of the 1990 Clean Air Act.

Section 107 of the Clean Air Act (CAA) establishes specific requirements to be met in order for an area to be considered for redesignation, including:

(a) A determination that the area has attained the annual standard for fine particles.
(b) An approved State Implementation Plan (SIP) for the area under Section 110(k).
(c) A determination that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the SIP and other federal requirements.
(d) A fully approved maintenance plan under Section 175A.
(e) A determination that all Section 110 and Part D requirements have been met.

Indiana has met all the above-requirements and has submitted an approved maintenance plan.

A maintenance plan provides for the continued attainment of the air quality standard by an area for a period of ten years after the U.S. EPA has formally redesignated the area to attainment. The plan also provides assurances that even if there is a subsequent exceedance of the air quality standard that measures in the maintenance plan will prevent any future occurrences through contingency measures that would be triggered.

The redesignation requests for ozone and $PM_{2.5}$ did not include reliance upon federal programs such as the Clean Air Interstate Rule (CAIR) to show continued attainment. In fact, the ozone redesignation request, dated June 2, 2005, page 25 stated specifically "U.S. EPA has modeled base case future years with existing emission controls only and shown that Warrick and Vanderburgh Counties will attain the 8-hour ozone NAAQS without proposed additional national emission control strategies." At that time, CAIR had not yet been implemented. For the $PM_{2.5}$ redesignation request, IDEM used modeling that included scenarios both with and without reductions from CAIR or the proposed Transport Rule. See Section 7.1, "REQUEST FOR REDESIGNATION AND MAINTENANCE PLAN UNDER THE ANNUAL NATIONAL AMBIENT AIR QUALITY STANDARD FOR FINE PARTICLES, Southwestern Indiana Area", January 2011, page 36. Indiana found that in either situation, "and the future year design values were determined without the emission reductions associated with CAIR".

To read more about the redesignation and maintenance plan go to http://www.in.gov/idem/files/evv_fine_redesignation.doc.

Also, see the response to U.S. EPA Comment 1 for a description of the ozone analysis. See Response 44 under comments received by the public for a discussion of $PM_{2.5}$.

Comment 40: IDEM needs to model Particulate Emissions to show the effect of construction and operation of the plant.

Response 40: IDEM has conducted the Air Quality Analysis in accordance with U.S. EPA and Indiana requirements. That analysis, which is included in the draft permit documentation, included an evaluation of PM_{10} and $PM_{2.5}$.

Comment 41: IDEM needs to model ozone. Ozone is a problem in Green and Clark Counties, we need modeling to see if it is a problem in Spencer County.

Response 41: For a description of the ozone analysis, see the Response to U.S. EPA Comment 1.

Health Concern Comments

Comment 42: The calculated Potential to Emit of the emissions in this permit may be wildly inaccurate, posing serious potential harm to the public and the environment. As of January 2011, the EPA claimed only unpublished, laboratory confirmation of the use of surrogate emissions in determining coal combustion emissions; the only way to know the actual emissions is to constantly monitor each and every pollutant, and this permit does not require that. How, in light of the preceding, does this permit adequately protect the public health and environment from pollution? The data which is being presented by the Gasification proponents needs to be verified by research that is conducted by investigators who are absolutely independent. Is this permit doing the best job it can in preventing pollution?

Response 42: As an initial matter, this project does not combust any coal, and so IDEM has not used coal combustion emission factors. The coal and petroleum coke feedstocks are instead chemically converted through a fully enclosed gasification process. Gasification is a process by which a solid fuel source is subjected to very high temperature and pressures to create a chemical reaction that leads to the creation of synthesis gas or “syngas”. The proposed IG facility will further clean and convert the produced syngas to create a substitute natural gas or “SNG.”

The permit contains enforceable limits on the operation of sources and the emissions of sources that serve as the controlled potential to emit (“PTE”) for those units. For sources where the PTE is not subject to such a limit, IDEM estimated the PTE using the best available emission information, including emission factors collected by U.S. EPA and published under the AP-42, which is available at http://www.epa.gov/ttnchie1/ap42/ on the Internet. Other estimates underlying this permit are based on the company’s extensive knowledge of the processes that will be used, equipment vendor data and many years of experience with similar sources of emissions. For an explanation of why the BACT review process promotes accurate development of emissions estimates, see the response to Public Comment 35. The bases for many of the emission factors used in this permitting action are explained in more detail in responses to other comments. See, for example, responses to Sierra Club Comments 28, 29, 31, 34, 36, 38, and 44.

The permit contains emission limits that the source must meet. Each D section of the permit also contains a subsection with all the applicable compliance determination requirements, which show how the source will comply with its emission limits and standards. Each D section also sets out the applicable compliance monitoring, record keeping and reporting requirements that will create additional emission information to ensure that the process is always in compliance with its emission limits. In cases where the potential magnitude or variability of the emissions justifies it, the permit requires continuous pollutant emissions monitors and or stack testing.

Comment 43: IDEM received a substantial number of comments regarding the health impact of the ambient air pollution levels in Spencer County, both now and what they will be after this source begins operation. These concerns included the many possible effects the emissions may have on them, such as human health effects, including increased cases of cancer and asthma. IDEM has set forth some of these comments verbatim below:

We are way too polluted now. Has anyone ever done a study on how much greater the cancer threat is here than in other places? I've read that we are the 16th most polluted county in the nation.

The people in Spencer County and the surrounding Counties have a tough decision to make concerning the many factors that weigh into this permit. Some of these factors include, increase medical problems such as asthma, premature death, cardiovascular disease and decrease lung function.

As a resident of Rockport, I am very concerned about the added pollution a coal gasification plant will bring to our community. Approval of permit number 147-30464-00060 would expose the residents to greater heath risks. Spencer County already is high on the pollution levels. It's not fair to our younger generation to have them grow up in an unhealthy environment. I am not willing to trade my grand children's well-being for economic growth. Please don't approve this permit. Let rural America breathe.

The city is already exposed 24/7 to toxic pollutants that are producing deteriorating effects on the health of our County people. The effect on the public health must be considered.

Indiana Gasification’s emissions, when added to emissions from AEP Power Plant and AK Steel are an unnecessary and undesirable addition to air pollution load in Spencer County and surrounding counties. Cumulative load affects air quality and health.

My family members have cancer. People who live here their whole lives aren’t susceptible to cancer right away, while those who move to Spencer County get cancer in just a few years. I don’t think people realize how many people are dying in this county from cancer. This area has one of the highest cancer rates in the United States

Air Quality is important.

On site releases of toxics to air, water and land in Indiana according to TRI, increase 18 percent in 2010. Carcinogen releases were up 16% with a 21% increase in Bioaccumulative toxics (BT).

According to scorecard.org, Spencer County has 26,507,023 pounds of chemicals released to the atmosphere. Vanderburgh County has 1,185,000. Spencer County is the top polluted county in Indiana. AK Steel emits 22,707, 000 and 812,000 according to scorecard.org, while the Rockport Power plant emits just 3,731,543.

Indiana is the worst state in the nation for chromium and nickel pollutants.
Indiana is one of the worst states for chromium, nickel as well as arsenic, lead, mercury, selenium, and acid emissions.

We already have so many entities that are polluting the immediate area that it is hard to believe that they are considering another one?

I don’t want to live here if it gets so bad that you can’t breathe without getting a respiratory problem.

Asthma: Children in Evansville are five times more likely to be hospitalized with Asthma than their counterpart in Fort Wayne.

Response 43: After the public comment period IDEM performed further information gathering and analyses. A screening analysis was conducted for air toxics in Spencer County, Indiana. This screening was performed to help address questions and concerns that the public raised during a public meeting pertaining to the permitting of the Indiana Gasification facility. The review consisted of reviewing current heath information, reviewing the existing 2005 National Air Toxics Assessment (NATA) (released in early 2011), and performing air dispersion modeling for major sources in the area.

The analysis shows that there is no increased asthma or cancer incidence in Spencer County and that the county is rated as one of the best in the state for low chronic illness. The 2005 National Air Toxics Assessment (NATA) showed that air toxics emissions and estimated concentrations in Spencer County are below State and National averages. Air dispersion modeling indicates that cancer risk and non-cancer hazard are below or within the expected risk range and that a majority of the risk from toxics would fall on the property of major sources, not in areas where the public lives or would have access.

Current Health Information – Asthma and Cancer rates

Review of the current data available to the ISDH and IDEM demonstrated that residents in Spencer County have not been at increased risk for exacerbation of asthma (measured by emergency department and hospitalization encounters). Table 1 shows the age adjusted rate for asthma and the state ranking for that rate. Figure 1 shows the ranking of each county in Indiana for age-adjusted emergency department visits for Asthma in 2009.

Table 1 - Age-adjusted Emergency Department (ED) and Inpatient (IP) Asthma-related Encounter Rates and Ranks, Spencer County, 2006–2010

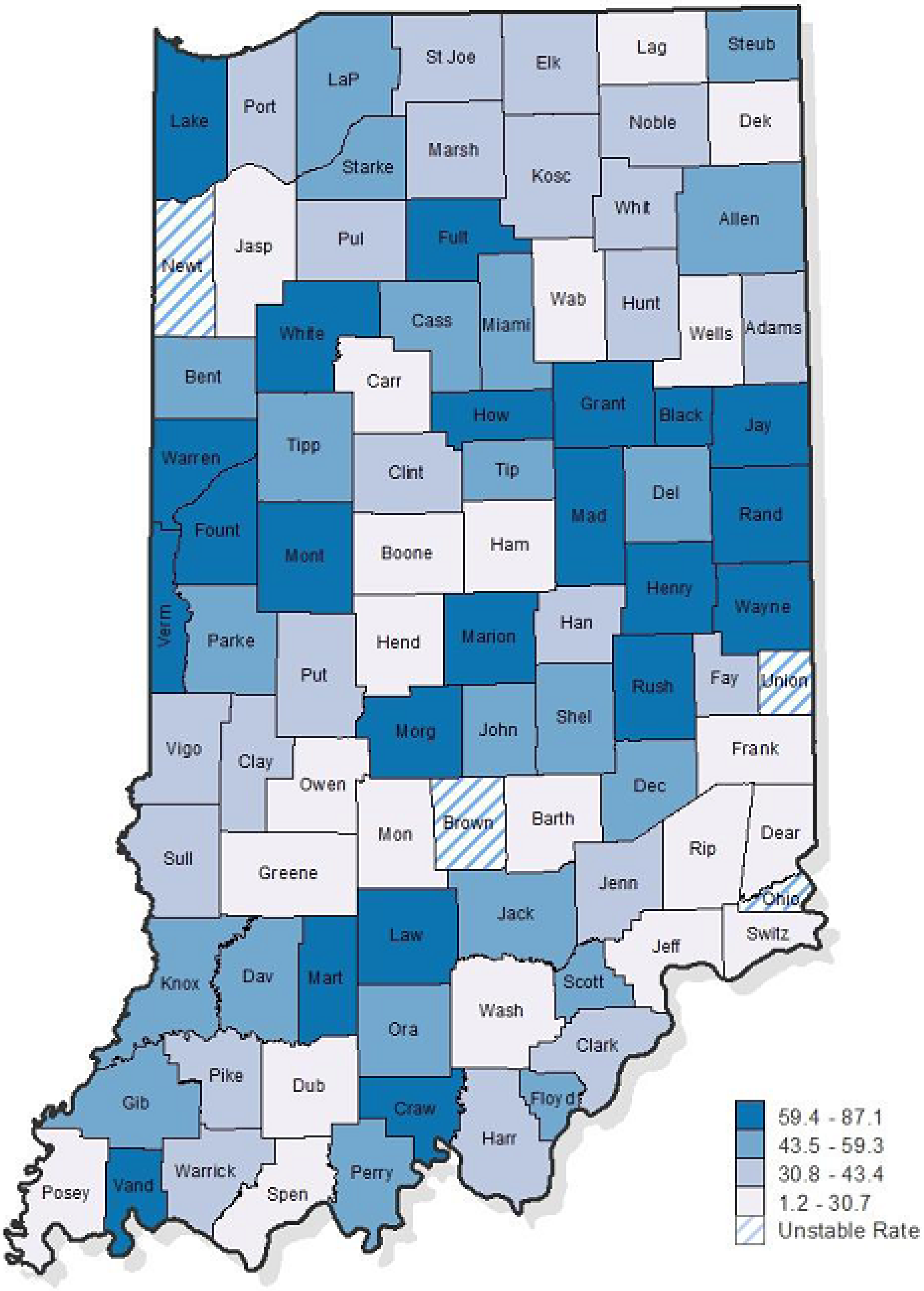
	Age-adjusted Rate~	**Rank in State (Out of 92; lower is better)**
SPENCER CO ASTHMA-RELATED EMERGENCY DEPARTMENT VISITS*	46.2	15
SPENCER CO ASTHMA-RELATED INPATIENT ADMITS*	17.0	7

**Based on ICD-9 code of 493 (asthma) within first three diagnoses codes*
~Age-adjusted rate per 10,000 population

Source: Indiana Hospital Association's Hospital Discharge Database Figure 1 is a map generated for the 2011 Burden of Asthma in Indiana Report (http://www.in.gov/isdh/files/BR_Asthma_5-11-11gw.pdf). This map depicts asthma-related emergency department rates based on patients having a primary diagnosis of asthma. Spencer County is in the "white" zone, showing that it had a rate during 2009 that was in the lowest (best) quartile in the state.

Figure 1 – Age-Adjusted Asthma Emergency Department Visits in Indiana 2009

Age-Adjusted Asthma Emergency Department Visits, Indiana, 2009



Source: Indiana Hospital Association's Hospital Discharge Database

Table 2 below shows the cancer rate compared to the rest of Indiana for overall and receptor specific cancers. Spencer County is not at an increased risk for cancer incidents. In fact, Spencer County's overall age-adjusted cancer incidence rate (425.3 cases per 100,000 people) during 2004–2008 was statistically lower than the Indiana rate (475.6 cases per 100,000 people). There were no increased statistical differences between Spencer County's rates and the state's rates for the leading cancer types (Table 2).

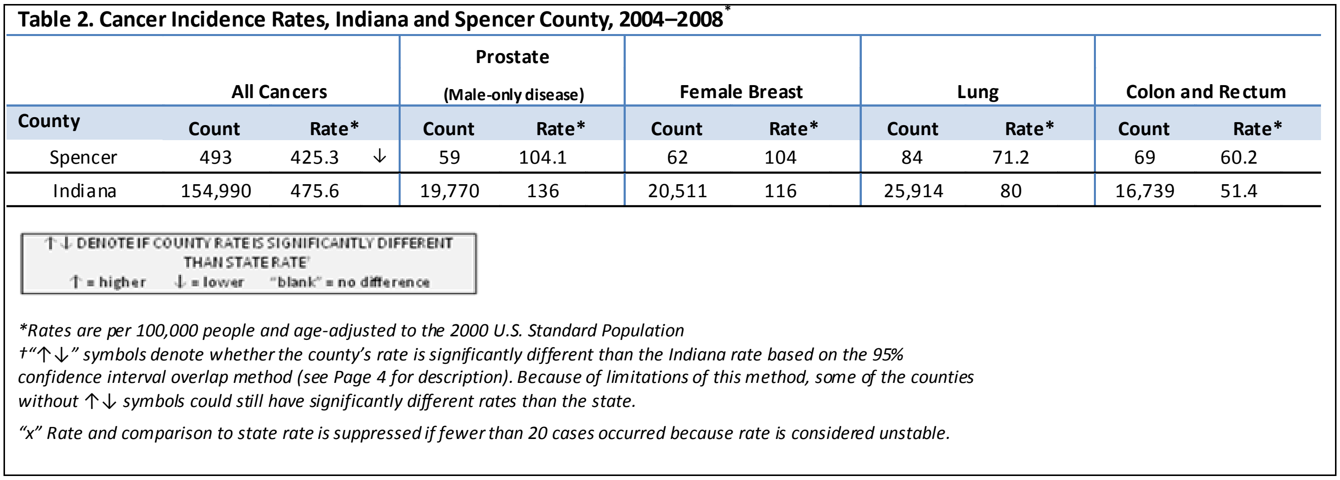


Table 2. Cancer Incidence Rates, Indiana and Spencer County, 2004–2008*

	All Cancers			Prostate (Male-only disease)		Female Breast		Lung		Colon and Rectum	
County	**Count**	**Rate***		**Count**	**Rate***	**Count**	**Rate***	**Count**	**Rate***	**Count**	**Rate***
Spencer	493	425.3	↓	59	104.1	62	104	84	71.2	69	60.2
Indiana	154,990	475.6		19,770	136	20,511	116	25,914	80	16,739	51.4

↑ ↓ DENOTE IF COUNTY RATE IS SIGNIFICANTLY DIFFERENT THAN STATE RATE†
↑ = higher ↓ = lower "blank" = no difference

**Rates are per 100,000 people and age-adjusted to the 2000 U.S. Standard Population*
†"↑↓" symbols denote whether the county's rate is significantly different than the Indiana rate based on the 95% confidence interval overlap method (see Page 4 for description). Because of limitations of this method, some of the counties without ↑↓ symbols could still have significantly different rates than the state.

"x" Rate and comparison to state rate is suppressed if fewer than 20 cases occurred because rate is considered unstable.

Source: Indiana State Cancer Registry (http://www.in.gov/isdh/24360.htm)

National Air Toxics Assessment

The United States Environmental Protection Agency (U.S. EPA) conducted the most recent National Air Toxics Assessment (NATA) in 2005. The NATA is a large scale evaluation of air toxics that examines many sources of air toxics. The evaluation looks at not only major sources of air toxics, such as factories, but also emissions from vehicles, small sources, and background air toxics. The NATA estimates what level of pollution people will be exposed to and the potential risk of developing health effects over a life time (70 years) when breathing those toxics. The NATA reports risk estimates based on the average concentrations over a census tract. There are five census tracts in Spencer County and 1,412 census tracts in the State of Indiana. The NATA looks at both cancer and non-cancer health effects.

For cancer risk, the highest tract in Spencer County was ranked 979th in the state of Indiana. The highest cancer risk for that census tract from major sources in the NATA was 0.67 excess cancer cases in a million people. That means that if one million people inhaled the same air for 24 hours a day, 7 days a week, 52 weeks a year for 70 years, there would be at most 0.67 extra cancer cases per million people. The average for Spencer County from point sources is 0.48. This is well below the average calculated for Indiana of 2.2 and the national average of 1.6. When considering the risk from all sources, including background, Spencer County's risk is estimated at 2.9 excess cancer cases per million people. This is also less than the Indiana average of 3.6 and the national average of 5.0 excess cancer cases per million people.

For non-cancer hazard, NATA calculated respiratory and neurological hazards. This screening analysis combined the two different health endpoints to get one non-cancer hazard quotient which is an extremely health protective approach. For all census tracts in Spencer County the non-cancer hazard was less than 1. The highest tract was 0.76. For non-cancer hazards any result of less than 1 indicates that adverse health effects from the pollutant are extremely unlikely to occur.
http://www.epa.gov/ttn/atw/nata2005/tables.html

Air Toxics Emissions

Emissions estimates used in the Spencer County air toxics analyses were based on 2008 information for the three major sources in Spencer County. These sources are: AEP-Rockport, AK Steel Corporation and American Iron Oxide Company. These emission estimates were based on reported fuel process rates, EPA emission factors and existing control equipment. The 2008 inventory estimates were then updated with 2010 state reported and Toxic Release Inventory data where possible. These emissions were combined for each source to come up with a combined source air toxic total. For the screening analysis, the emissions were estimated at 1,259.1 tons. 1,239 tons of the total emissions were from AEP-Rockport.

For the 2005 NATA there were a total of 5,221 tons of air toxics in Spencer County, with hydrochloric acid estimated at 4,582 tons. Indiana's 2010 inventory for emissions is more current and takes into account recent control equipment installation at the AEP-Rockport facility.

Air Toxics Dispersion Modeling Evaluation

An AERMOD modeling analysis was conducted using existing modeling parameters for the four major point sources in Spencer County (the three large existing facilities mentioned above and the new proposed Indiana Gasification facility). Indiana Gasification parameters were based on available technological information and permit application data. The other three major sources' stack locations and release parameters were retrieved from the IDEM modeling database and analyzed at the emissions point level. Only these major point sources were considered for this analysis. The AERMOD run used meteorological data from Evansville, Indiana surface station and mixing heights from the Peoria, IL upper air station. The data was preprocessed minute by minute for 2006-2010. Terrain data was factored in for all sources and receptors. Building data was available for Indiana Gasification and the downwash for those buildings were used in the analysis. The screening analysis contained 1804 receptors in a 20 km by 20 km grid around the Indiana Gasification facility. Boundary data for Indiana Gasification was available and no receptors were placed on that source's property. Boundary data was not used for the other sources and receptors were located on their properties.

The annual estimated concentration for 2006 to 2010 was averaged into a single concentration for each receptor. For each facility, the estimated concentration for each air toxic was calculated based on the source's modeled impact and the estimated emissions. The concentration was then used to calculate cancer risk and non-cancer hazards for each source. The cancer Unit Risk Factor (URF) and non-cancer Reference Concentration (RfC) were taken from the most recent version of U.S. EPA's Chronic dose-response Table 1 (http://www.epa.gov/ttn/atw/toxsource/summary.html).

The highest modeled cancer risk based on the receptor grid was 1.2 excess cancer cases in a million. This was the only receptor over one in a million. The average for all the receptors was 0.15 excess cancer cases. Indiana Gasification highest excess cancer case receptor was 0.006. The average cancer risk for Indiana Gasification over all receptors was 0.0026 excess cancer cases. The pollutants driving the risk were arsenic, chromium VI, methylhydrazine, and formaldehyde. U.S. EPA uses a range between one in a million to one hundred in a million excess cancer cases when evaluating whether the estimated risk is at a level where action should be taken. Generally, U.S. EPA considers risk estimates over one hundred in a million to be at levels where action or more investigation is required. Risks that fall between one in a million and 100 in a million level generate decisions and actions taking into account the assumptions used to determine the estimate. Risk estimates below one in a million are usually considered as not requiring further action.

For non-cancer hazard quotient, the highest receptor in the study area is 0.21. Non-cancer drivers were hydrogen sulfide, acrolein, hydrochloric acid, manganese, cadmium and arsenic. A non-cancer hazard quotient under 1.0 is commonly recognized to be health-protective. Hazard quotients over 1.0 indicate that further investigation may be necessary but does not necessarily mean that health effects are expected. The average for the study area was 0.025. For Indiana Gasification, the highest receptor hazard quotient was 0.21 and the average was 0.02. These are health protective scenarios and are very likely to be greater than the actual non-cancer hazard quotient.

Comment 44: Several commenters expressed concerns over the effect of the source's emissions on wildlife, water, farm ground, and crop yield and the quality of life.

Response 44: The permit documents include an Additional Impact Analysis in which IDEM concluded that "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 (see Air Quality Analysis, pp. 12-13 of 49).

The federal Clean Air Act requires the U.S. EPA to set National Ambient Air Quality

Standards (NAAQS) for six criteria pollutants. These standards are set by U.S. EPA at levels that protect human health, including the health of sensitive persons, such as asthmatics, children and the elderly. The NAAQS are often referred to as the federal health standards for outdoor air. The secondary NAAQS standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Spencer County is currently in attainment status for all criteria pollutants.

More information about these pollutants is available at www.epa.gov/air/airpollutants.html on U.S. EPA's website. The complete table of the NAAQS can be found at the www.epa.gov/air/criteria.html website. Detailed information about the effects of these common pollutants is available at www.epa.gov/air/urbanair/. IDEM conducts sampling of the ambient air at monitoring stations around Indiana. This air monitoring is conducted to measure whether the NAAQS are being met. Information about Indiana's air monitoring system and monitoring results is available at www.idem.IN.gov/4116.htm. Information about current and expected air pollution levels throughout Indiana is on IDEM's SmogWatch site at www.smogwatch.IN.gov on the Internet.

IDEM's Office of Water Quality (OWQ) manages waste water permitting. If the source needs a water permit it will have to apply to OWQ. Information about water permitting is available at http://www.in.gov/idem/4869.htm on the Internet.

Comment 45: One commenter was concerned over the effect of increased truck traffic on area roads.

Response 45: The permit includes air quality-related requirements that apply to fugitive dust emissions from plant roadways. IDEM has no authority to consider the effect of increased truck traffic on public area roads. Issues of traffic safety are left to local government agencies that set and enforce traffic controls.

Fugitive Emission Comments

Comment 46: IDEM barely addressed the very real issue of fugitive emissions from the plant except to require dubious Best Management Practices for operation and maintenance of this experimental plant. The problem is that converting coal into other hydrocarbons creates waste streams that are known to be extremely acidic and caustic as the coal is refined. Those high and low Ph wastes are known to quickly consume the many seals that are part of such a sophisticated chemical conversion that is required to gasify coal. Usually Best Management Practice is the accepted way to deal with keeping fugitive emissions from escaping a plant. However, this plant has other obstacles that might well keep these emissions from being adequately kept in check.

Response 46: The water quench system in the gasifier readily captures and dilutes the acid compounds formed when the coal and coke are gasified. This water is then removed from the gasifier and managed as a conventional wastewater stream. Later in the process, sulfur compounds that remain in the syngas are intentionally converted to sulfuric acid which is a useful product that will be sold for commercial use. As noted in response to public comment 23, the LDAR provisions of this permit, where appropriate are required for piping and components with the potential to leak air pollution. As such, leaks of any origin will be detected and addressed through maintenance and repair requirements of the permit. It should be noted that sulfuric acid is used commonly in manufacturing and there is extensive experience in the specification of metallurgy and the selection of materials for components and piping that are resistant to acid corrosion.

Global Warming Comments:

Comment 47: Global warming is a significant event that will have many dangerous, deadly and costly impacts. The use of syngas as a fuel produces more CO_2 thus, providing a second dose of potential effect on global weather patterns.

Response 47: In response to concerns over climate change, U.S. EPA promulgated new regulations under the PSD program requiring facilities that emit greenhouse gases (GHG) above certain thresholds to apply Best Available Control Technology (BACT) to GHG emissions. IDEM has applied these regulatory requirements in this permit, as set out in the GHG BACT analysis in the draft permit documents. BACT requirements have been applied to the syngas flare, which is the only emission point at the facility where syngas is combusted, and to fugitive emissions of syngas. Syngas is not used as a fuel at the facility.

General Comments:

Comment 48: How is the coal to be gasified? Is this a proven technique and industrial technology, with known, demonstrated, and measured emissions? How does this differ from processes used to produce utility gas or city gas at or about the year 1900? Where can be found reports of emissions from operating industrial scale coal gasification plants?

Response 48: A brief description of the gasification process is summarized in the applicant’s permit application page 2-1 which explains that gasification is the process by which a solid fuel source is subjected to very high temperature and pressures to create a chemical reaction that leads to the creation of synthesis gas or “syngas”. The proposed IG facility further cleans and converts the produced syngas to create a substitute natural gas or “SNG.”

The modern gasification process is different than the turn of the century “city gas” generation process, which was used to thermally and destructively distill gases from coal for use as a gaseous fuel. The modern gasification process is a proven technology with a number of US and world wide applications. The following five plants are operating in the United States today:

- Wabash River in Indiana for power generation,
- Tampa Electric Polk Power in Florida for power generation,
- Great Plains Synfuels in North Dakota making SNG,
- Eastman Chemicals in Tennessee making chemicals, and
- Coffeyville Resources in Kansas making fertilizer.

In the permit review of best available control technologies (BACT), each emissions unit was compared to the most relevant recent permitting of a similar emission unit. For the equipment unique to gasification facilities, comparisons were made in the BACT analysis to recently proposed and permitted facilities such as the Duke Edwardsport IGCC in Indiana, Power Holdings SNG plant in Illinois, Lake Charles Cogeneration in Louisiana, and Cash Creek Generation in Kentucky. These gasification facilities have not yet begun operation, but they have all been permitted within the last 5 years and their proposed limits represent an appropriate comparison in establishing expectations for the IG facility. Discussion of the required emissions performance of these proposed similar facilities are presented in the BACT section of the TSD document beginning on page 638.

Comment 49: IDEM did not address the overall economics of the facility. Indiana Gasification is bound by a contract with the State of Indiana (which obviously creates a distinct conflict of interest in IDEM granting this permit) that requires it to sell its output to the State of Indiana for a price that is considerably higher than the price of its primary competitor, natural gas. Because the price is higher but not really high enough to adequately cover their cost of production, there will be tremendous pressure on the operator to keep operating and maintenance cost to a minimum. As a result, those pressures will impact the operator's ability to adequately implement Best Management Practices designed to hold down fugitive emissions.

Plant should be put in a county with a lower level of air pollution. We want a tourist based economy.

Natural gas supplies are plentiful, this plant is not needed. Electric rates will go up.
Coal is the bane of economic development.
Government should not be loaning money to company. State law will make residents pay a premium for natural gas.

Response 49: IDEM is not authorized by Indiana law to consider the economics of an industry or economic planning when issuing an air permit decision.

Comment 50: The significant budget cuts at IDEM have resulted in IDEM having an increasingly poor inspection record for facilities like this and it is clear that the conditions for sometimes high levels of fugitive emissions that would go unchecked until the next, infrequent IDEM inspection, might take place. If that happened and those emissions were added to the existing level of toxic emissions in the immediate vicinity, a dangerously toxic situation could rapidly develop and IDEM would be in the dark until their next inspection.

Response 50: IDEM monitors the levels of harmful emissions in the ambient air at locations around Indiana. The monitoring results from these stations are available at http://www.in.gov/idem/4652.htm on the Internet. In addition, IDEM projects daily ambient air concentrations, based on current weather patterns, at its SmogWatch site at http://www.in.gov/apps/idem/smog/ on IDEM's website.

Under this permit, IG will have an obligation to submit quarterly deviation reports reporting any deviations from the requirements of the permit. Not doing so can result in IDEM bringing an enforcement action. Separate from inspections, IDEM will receive test reports and emissions information that will allow IDEM to determine when violations have occurred.

IDEM response time to violations depends on the severity of the reported violation. IDEM responds to all reports of violations. Responses to violations vary depending on the severity of the violation and can be a warning letter, a fine or even criminal prosecution. IDEM has sufficient compliance inspectors. IDEM has inspection tools and practices to determine noncompliance, even if a source is not reporting deviations.

IDEM will enforce the permit as issued. IDEM will review the severity of any violation and the source's history of violations in determining what enforcement action is necessary and what are appropriate penalties.

IDEM inspects sources like IG on the average of once per year. IDEM will make more frequent inspections if the source has a history of violations or is the subject of complaints from the public. Any person may report any suspected violation by contacting IDEM. You can file a complaint with IDEM three different ways:

1. Submit a complaint online at http://www.in.gov/idem/5275.htm on IDEM's

website,

2. Call the Complaint Coordinator toll free at (800) 451-6027 ext. 24464, or

3. Print, complete, and mail a paper-based Complaint Submission Form (now available on the IDEM Forms page at http://www.in.gov/idem/5157.htm#agency

IDEM handles all inspection, compliance and enforcement issues on a case-by-case basis. The current air inspector for this area is:

Inspector Name:	Andrea Alltop
Phone No:	812-380-2315
Email Address:	aalltop@idem.in.gov
Address:	IDEM, Southwest Regional Office, P.O. Box, 1120 N. Vincennes Avenue, Petersburg, Indiana 47567.

Comment 51: I beg you not to issue the noted Air Permit for Indiana Gasification. This project is an example of the misuse of the powers of government to 1) harm the environment, 2) hasten the depletion of a natural resource, and 3) impose a rate increase on residential Indiana rate-payers to the benefit powerful corporations.

Response 51: Detailed information providing an evaluation of the environmental impact of the source is included in the draft permit documentation, and IDEM has determined that the source, as permitted, meets the requirements of the Prevention of Significant Deterioration and other Clean Air Act programs. IDEM has no authority to consider concerns over rate increases when issuing a decision for an air permit.

Comment 52: The people in Spencer County and the surrounding Counties have a tough decision to make concerning the many factors that weigh into this permit. Some of these factors include increase medical problems such as autism.

Response 52: IDEM has set out information and analysis regarding air pollution and health in response to Comment 43, above. The source's permit reflects all of the applicable air pollution controls and limitations for its emission equipment. The Center for Disease Control is studying autism. More information about those studies, including a summary of last year's workshop with Autism Speaks, is available at http://www.cdc.gov/ncbddd/autism/index.html on the internet.

Comment 53: **T**he area in which Indiana Gasification is proposing to build the synthetic gasification plant is in the 100 year flood plane of south Spencer County. Not only is all of the area in the flood plane but there are also natural wetlands within the area. We oppose the building of this project for many reasons; among them is the fact that the construction of this plant, in this location, would cause future flood waters to adversely affect other properties.

Response 53: The applicable air permitting laws and rules do not address floodway or wetlands issues. The Indiana Department of Natural Resources-Division of Water, (317) 232-4160, water_inquiry@dnr.IN.gov has jurisdiction over construction in the floodway. If applicable, the owners of the proposed gasification plan would need to go through the Construction in the Floodway permitting process.

If applicable, the applicant would be required to obtain proper permits for proposed wetland impacts. Specifically, the IDEM-Section 401 Wetlands program requires applicants to obtain a State certification for jurisdictional impacts. In addition, an applicant would be required to obtain a Section 404 permit from the US Army Corps of Engineers for wetland impacts. Finally, the IDNR-Division of Water also regulates wetlands and has similar requirements. However, its jurisdiction would only fall within the floodway.

Comment 54: The President rejected to build a pipeline to carry oil from Canada to Texas. Why would he approve this pipeline for CO_2?

Response 54: There are a number of interstate permits in the US that support the transport of fuels and products such as CO_2. In fact, there are a number of CO_2 pipelines already permitted and in place. IDEM does not have authority over interstate pipeline approvals and cannot address that process in the context of this permit review. IDEM can and will enforce the emissions limits in the permit. If the pipeline is not constructed the source may have to apply to IDEM to revise its limits on carbon dioxide emissions. If that occurs there will be a new public notice process and a new opportunity for the public to comment on any proposed permit changes to the Best Achievable Control Technology requirements for Green House Gases (GHG BACT).

Comment 55: What is the current status concerning the clean air permits for the coal gasification plant being proposed for Spencer County?

Response 55: IDEM has now issued the final permit decision, as set out in the Notice of Decision document.

Comment 56: Big Plains Gasification Project in North Dakota: Why is there no TRI data available for this plant?

Response 56: IDEM has not been able to locate a source named “Big Plains Gasification” in North Dakota. The North Dakota Department of Health, which handles air permits in North Dakota, can be contacted at 701-328-5188 or contact Lew Dendy at NDDH at ldendy@nd.gov by e-mail.

Comment 57: IDEM needs to assess and limit pollution, not just rubber stamp the application. This is a done deal by politicians in the coal industry to show us who is in control of the power structure of the State of Indiana. The Governor is enamored of clean coal. When was the last time IDEM denied an application or modified one?

Response 57: IDEM’s air permit process determines the air permit regulations that apply to each emission unit at a source and the source overall, using information in the application materials. If an applicant has provided adequate information to allow IDEM to determine the applicable air quality regulations and draft a permit with appropriate requirements, IDEM is required to draft and issue the permit. In applying the applicable regulations to the permitting process, IDEM very often requires controls or requirements beyond what was initially proposed by the applicant. When a source determines that it cannot go forward with a project due to the emission limitations or other condition in a draft air permit, it may withdraw its application.

Using information in IG’s permit application and supplemental materials, IDEM drafted the proposed permit documents for public notice and comment. The public has commented on the proposed permit, including specific comments on permit conditions and permit limitations. IDEM has responded to those comments in this Addendum, making changes to permit terms as necessary.

Comment 58: Syngas could be used in cars, have other good effects but this project is not a good thing. We should use wind, solar and mass transportation. We should focus on Renewable Energy.

Response 58: Determining national or state energy policies, relative to such things as power generation and mass transit, is not within the scope of the IDEM review. IDEM has no authority to direct the focus of energy generation or use.

Comment 59: No one commented on FESOP 087-27799-03302 which has 3,850 tons of emissions and is 4000 feet from this proposed plant.

Response 59: The amount of public comment on an air permit for another plant does not affect IDEM's consideration of the public comments on this plant.

Comment 60: What will the effect of sequestration be on our local area?

Response 60: There is no provision for sequestration in this permit. Carbon Capture and Sequestration was evaluated but it was determined to be technically infeasible for this project. Therefore the source will not be required to perform sequestration.

Comment 61: What effect will transportation of coal by rail and barge have on community?

Response 61: IDEM is not authorized to consider the effect of rail or barge traffic moving through the community outside of the source's property. The permit review addresses the air emissions associated with coal and coke handling at the facility and imposes Best Available Control Technology requirements to minimize emissions associated with those handling activities at the site.

Comment 62: Surface Mining's destructive practices will increase. Mining releases methane, a GHG.

Response 62: IDEM is not authorized to consider the effect of mining activities that may increase as a result of issuing the permit.

Comment 63: Jobs are not worth pollution.

Response 63: IDEM is not authorized to consider the number of jobs that may be created by a source when issuing an air pollution permit.

In support of the Project

Comment 64: **In support of the Project:**

(a) I believe this permit should be approved. A few local and a large number of out of town (and state for that matter) have voiced some concerns about this permit and this plant in general, mainly because of the word coal. I have a copy of IDEM permit #147-29070-03302 for a asphault plant that is located at 1021 N. ST. RD. 66 Rockport, IN. That permit had an allowable emission rate of 385 tons per year for a ten year period. To my knowledge not a single comment against that permit was submitted. Now why would a group of people be against one source of pollution and not another that emits more? I believe IDEM did an outstanding job on this draft and should approve it as soon as possible.

(b) The Clean Air Task Force **(**CATF) support IDEM's inclusion of a greenhouse gas best available control technology ("BACT") emission limit for the acid gas removal ("AGR") system at the facility as mandated under both the Clean Air Act and State of Indiana requirements, also we support IG's efforts to further the use of CCS technology in achieving this limit. The Project stands to be an important step towards more widespread use of CCS generally, and in the central US in particular, especially through development of a CO_2 pipeline to injection sites in the Gulf Coast states and we support the selection of a phased-in limit for CO_2 over the initial three years of the facility's operation.

(c) The Coal conveyor system will be enclosed with dust collectors, therefore the fugitive dust will not be a problem. I am in support of the project.

(d) Toxic and carcinogen releases in Indiana have gone down, therefore I am in support of the project.

(e) Mercury release rate is decreasing in Indiana, therefore I am in support of the project.

(f) This plant will have lowest mercury emissions of any coal plant operating in Indiana.

(g) Rockport Power plant will scrub its emissions, maybe as soon as 2013.Therefore I am in support of the plant.

(h) Permit should be granted because CO_2 is going to be captured.

(i) This will be cleanest coal plant in the world.

(j) I appreciate IDEM and what they are trying to do for Spencer County.

(k) I support this permit and the project

(l) This is good public policy, Ind. Reg. Comm. Approved.

(m) Oil Recovery use of captured CO_2 will reduce dependence on foreign oil. I am in support of the project.

(n) We need jobs so that people can pay their bills and to support our local tax base. I am in support of the project.

Response 64: IDEM acknowledges that these comments are important to the commenters. However, these comments do not have any direct impact on how IDEM reviews and make decisions on air permit applications.

SIERRA Club Comments

Modeling Comments

Comment 1: IDEM FAILED TO FOLLOW THE REQUIRED PUBLIC PARTICIPATION REQUIREMENTS

IDEM did not follow the required public participation procedures. IDEM made some of the AERMOD files available at the public library but not all of them. In particular, the SO_2 and NOx modeling files were not available at the public library. We went to the public library and obtained 4 computer disks which we were told were all of the computer disks available. These contained $PM_{2.5}$ and PM_{10} modeling but not the SO_2 and NOx files. There was one excel file submitted under a September 29, 2011 cover letter but this only had some of the inputs listed and we do not even know if the inputs in the spreadsheet were the inputs actually used in the modeling. This is particularly problematic because as explained below, the SO_2 and NOx modeling claims to have predicted impacts very close to the significant impact level and contained numerous flaws. Therefore, IDEM should hold make these computer files available at the public library and then hold a new public comment period.

Response 1: A copy of the permit application was placed at the Spencer County Public Library within ten days after the application was filed with IDEM. IDEM placed all the draft permit documents at the library and also made them available at IDEM's offices and on IDEM's website. IDEM is not aware of the specific records request referenced in this comment, but the Library staff on February 8, 2012 also confirmed that these files, on a DVD, are available at the Library. IDEM is not aware of the commenter having contacted IDEM in order to obtain the modeling files at any time during this permitting action. No revisions to the draft permit are required as a result of this comment.

In addition, IDEM has no specific information to indicate Indiana Gasification, LLC did not comply with the public notification requirements. If specific evidence was provided to IDEM of a failure to comply with the requirements of 326 IAC 2-7-17(b) or 326 IAC 2-1.1-6 prior to issuance, IDEM would consider this information in its permit decision.

Comment 2: IDEM IMPROPERLY USED A SIL

To begin with, the 1-hour SO_2 SIL is not in Indiana's SIP. Therefore, IDEM cannot rely on it to issue a Title V permit. Furthermore, IDEM has offered nothing in the record to support the use of a SIL in general or a 7.80 ug/m3 1-hour SO_2. Thus, IDEM cannot rely on this SIL.

Response 2: Under the PSD program a new major source or major modification must complete an air quality analysis to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS). This analysis involves several steps and U.S. EPA has provided a screening tool known as the Significant Impact Level (SIL). The use of SILs are rooted in the *de minimis* exception observed in Alabama Power v. Costle, 636 F.2d 323, 360 (D.C. Cir. 1979). Historically, "EPA has allowed the use of several types of screening tools to facilitate implementation of the preconstruction review process to reduce the permit applicant's burden and streamline the permitting process for *de minimis* circumstances. These tools include …SILs…." 75 Fed. Reg. 64,864, 64,866 (Oct. 20, 2010) (final rule establishing SILs for PM2.5). SILs are used to determine whether emissions from a proposed major new stationary source or modification will have a "significant" impact on air quality in the area. If an individual source projects an increase in air quality impacts less than the corresponding SIL, its impact is considered to be *de minimis* and the permit applicant would not be required to perform a more comprehensive, cumulative modeling analysis. A cumulative analysis involves measuring the impact of the new source in addition to impacts from other existing sources in the area. If a cumulative modeling analysis indicates a violation of the NAAQS, the SILs may also be used to determine whether the proposed source's impact on a modeled violation is significant enough that it is considered to "cause or contribute to" the modeled violation of the NAAQS or increment.

For the 1-hour SO_2 and the 1-hour NO_2 standards, U.S. EPA provided an interim SIL. The interim SIL for SO_2 is 3 ppb (7.86 $\mu g/m^3$). See Memorandum from Anna Marie Wood, Acting Director, U.S. EPA Air Quality Policy Division, to Regional Air Division Directors, "Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration Program," at 6 (Aug. 23, 2010) ("SO_2 SIL Guidance"). U.S. EPA derived this value by using an impact equal to 4% of the 1-hour SO_2 NAAQS. Id. at 6. In so doing, U.S. EPA explained that it believes it is reasonable to base the interim 1-hour SIL directly on consideration of impacts relative to the corresponding 1-hour NAAQS. Id. See response to Sierra Club Comment 16 for additional discussion of considerations in setting an appropriate de minimis level. U.S. EPA stated that it was making the SIL "available to States with EPA-approved implementation plans containing a PSD program to use at their discretion." Id. at 5.

IDEM agrees with U.S. EPA's basis for this interim SIL value of 3 ppb, and the SIL was implemented in accordance with the SO_2 SIL Guidance. Thus, although the SIL for SO_2 is not incorporated into Indiana's SIP, it does not need to be in order for IDEM to utilize this screening tool.

Consistent with U.S. EPA's guidance, IDEM used the maximum 1st highest 1-hour concentration averaged over 5 years for comparison to the 1-hour SO_2 SIL of 3 ppb (7.86 $\mu g/m^3$).

Comment 3: Also, even if the use of the SIL was permissible, IDEM averaged five years of impacts and compared the average to the SIL. The proper analysis would be whether any one year exceeded the SIL. While, as explained above, we do not have the modeling files because IDEM failed to make them available at the library, we believe, based on the average being so close to the SIL, that at least one year was above the SIL. Therefore, a cumulative impact analysis is required followed by an additional public comment period.

Response 3: IDEM modeled SO_2 in accordance with U.S. EPA guidance. See Memorandum from Anna Marie Wood, Acting Director, U.S. EPA Air Quality Policy Division, to Regional Air Division Directors, "Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration Program," at 6 (August 23, 2010) ("SO_2 SIL Guidance"). Specifically, the SO_2 SIL Guidance provides:

> [W]e are providing an interim 1-hour SO_2 SIL value of 3 ppb to implement the federal PSD program. To determine initially whether a proposed project's emission increase will have a significant impact (resulting in the need for a cumulative air quality analysis), this interim SIL should be compared to either the following:
>
> - The highest of the 5-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data; or
> - The highest modeled 1-hour SO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data.

Id. (emphasis added). Because representative nearby National Weather Service data was available, IG used the first option listed above rather than collect 1 year of site-specific meterological data. Consistent with this guidance, IDEM used the maximum 1st highest 1-hour concentration at each receptor averaged over 5 years for comparison to the 1-hour SO_2 SIL of 3 ppb (7.86 $\mu g/m^3$).

Comment 4: THE MODELING USES IMPROPER EMISSION RATES

IDEM claims that the maximum emissions from the syngas flare startup, EU 001, is 0.70 lb/hr. TSD App A, pdf page 400, 491. IDEM claims the maximum emissions from shutdown flaring is 255.62 lb/event which IDEM coverts to 85.21 lb/hr. TSD at pdf page 492. IDEM provides no information on where it obtained these figures. The BACT limit is 0.35 lb/hr (3 hr ave) startup on sulfur free fuel, 85.21 lb/hr (3 hr ave) for shut down. TSD at pdf page 646. In contrast, the Illinois Environmental Protection Agency's ("IEPA") draft Construction Permit ("Draft Permit"), ID No. 021060ACB, for Christian County Generation LLC's proposed Taylorville Energy Center ("TEC") states that its highest SO2 emissions from its flare during startup is 9,036 lb/hr. AAF has a limit of 9510 lb/SSM event. TSD at pdf page 646. Duke Energy Edwardsport has a limit of 1396.7 lb/hr during peak of startup and this facility is approximately half the size of IG, that is 5000 T per day versus IG's 10,400 T per day. TSD at pdf page 646.

Response 4: The disparity for these limits for startups is based on the kind of fuel used for start up. Christian County Generation LLC's proposed Taylorville Energy Center and Duke Energy Edwardsport use coal as a start up fuel. IG uses methanol for its start up fuel. Methanol combustion has very little SO_2 emissions as compared to coal. IG has committed to using methanol as a start up fuel which gives lower lb/hr values for SO_2.

IG has also committed to slightly lower shutdown SO_2 emissions limits than these other facilities. This is due to IG's plan to initially depressure shutdown gasification process equipment through the wet sulfuric acid (WSA) plant to recover the sulfur rather than vent all vessel depressuration gases to the flare.

See Conditions D.2.4(3) and D.2.9.

Comment 5: The SO_2 modeling fails to consider SO_2 emissions when the flares are doing what they are designed to do, flare products, except the modeling does consider the hydrocarbon flare during startup on methanol. *See* spreadsheet submitted to IDEM under a September 29, 2011 cover letter, SO_2 tab. The modeling must model SO_2 impacts when the flares are flaring substances during upsets or malfunctions, which again, is how they are designed to do, so it is a completely reasonable worst case scenario.

Response 5: The federal Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) pre-construction permitting programs are two of the major ways that EPA and the states can regulate air quality. New major sources and major modifications to sources must be properly permitted under the PSD or NNSR program.

The startup and shutdown emissions for this facility have been calculated and included in the facility PTE, permit limits, and air dispersion modeling. The hydrocarbon flare is the only emissions point that has higher emissions during startup or shutdown than in normal operation – for the hydrocarbon flare, normal operation is operation with the pilot flame. For the criteria pollutants besides SO_2, startups represent the operating scenario resulting in the highest flared emissions. This comes from the use of the flare to control/combust vented syngas generated by the starting up gasifier before it reaches sufficient pressure to be routed to downstream processing. However, SO_2 emission from startup flaring is relatively small because the facility will be permitted to startup on methanol, which is essentially sulfur free. Instead, the maximum flare SO_2 emissions are from shutdown flaring. Although the gasification processes can be stopped without any flaring, a small amount of flaring will be needed to depressurize the equipment to allow it to be taken out of service for maintenance. Prior to depressurization, this shutdown equipment will contain coal/coke generated syngas which will have some sulfur content. As a result, as this gas is vented to the flare following a shutdown, SO_2 will be generated. Again, the modeling analysis for SO_2 included shutdown flaring.

No other facility equipment would require flaring due to startup or shutdown, or have higher emissions during such a period versus their normal emissions. Besides the gasifiers, the other facility equipment is designed and expected to startup, shutdown, and be maintained without requiring flaring or any excess emissions.

United States v. Louisiana-Pacific Corp., 682 F. Supp. 1141, 1158 (D. Colo. 1988) establishes that PTE includes only emissions that occur during normal operations:

> Any analysis of the definition of "potential to emit" must include a reference to the case of Alabama Power Co. v. Costle, 204 U.S. App. D.C. 51, 636 F.2d 323 (D.C.Cir. 1979) because the current definition above was promulgated in

> response to the D.C. Circuit's holding in that case. . . .
>
> The broad holding of Alabama Power is that potential to emit does not refer to the maximum emissions that can be generated by a source hypothesizing the worst conceivable operation. Rather, the concept contemplates the maximum emissions that can be generated while operating the source as it is intended to be operated and as it is normally operated. . . . Alabama Power stands for the proposition that hypothesizing the worst possible emissions from the worst possible operation is the wrong way to calculate potential to emit.

Louisiana-Pacific, 682 F. Supp. at 1157-58. Malfunction emissions are the result of events beyond the control of the owner/operator and are not reflective of a source operating under its physical or operational design. See 326 IAC 1-2-39 (Malfunction is"[a]ny sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.")

Malfunctions do not represent the way the facility is intended to operate or the way it will normally operate. The Commenter suggests that malfunction emissions should be included in modeling because the flares are "doing what they are designed to do." However, a flare is a safety device that is not an independent operation from the process it serves. The facility has been designed in such a way as to prevent the need for flaring in normal operation, outside of startups and shutdowns, to minimize the possibility of malfunction flaring, and to minimize the amount of emissions that must be flared when flaring does occur. The permit contains limits on startup and shutdown flaring as well as several other requirements that apply to all flaring events, including malfunctions. However, not every possible scenario can be covered in a design. Malfunction of equipment requiring use of the flare may still happen. The flare is the control and not an independent operation, and it is not appropriate to include malfunction emissions in modeling merely because the malfunction emissions pass through a flare.

EPA's Guideline on Air Quality Models found in Appendix W to 40 C.F.R. Part 51, fully supports the view that malfunctions are not considered to be part of normal operating conditions for purposes of modeling a source's potential impact. The Guideline explains that "the source should be modeled using the design capacity . . . ." 40 C.F.R. Part 51, Appendix W, Sec. 8.1.2. The Guidelines further provide: "Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions." 40 C.F.R. Part 51, Appendix W, Sec. 8.1.2 fn.a.

More recent EPA modeling guidance supports the approach adopted by EPA in the Guidelines. In connection with modeling for the 1-hour NO_2 NAAQS, EPA recommends that the reviewing authority may consider operating scenarios that are relatively continuous and may exclude certain types of intermittent emissions. See March 1, 2011 Memorandum from Tyler Fox, Leader, EPA Air Modeling Group at 2.

Malfunction events that may result in excess emissions are not reflective of the source operating as designed. Accordingly, IDEM was not required to include such events in its modeling calculations.

Comment 6: Similarly, the TSD acknowledges that during an upset, acid gases can be routed to the acid gas flare. TSD at pdf page 403, 494. However, the emission rates used for ambient impacts analysis as well as for PTE completely ignored emissions when acid gases are routed to the acid gas flare. *Id.* Thus, not only is the ambient impacts analysis for SO_2 inadequate, the ambient impact analysis for NOx, PM_{10}, $PM_{2.5}$ and the synthetic minor HAPs determination are also invalid.

Response 6: The Acid Gas Flare is used only for relief protection during upsets or malfunctions of the Wet Sulfuric Acid (WSA) plant. See Response 5 under the Sierra Club comments regarding consideration of upsets and malfunctions in calculating PTE and modeling impacts.

Comment 7: The draft permit contains no emission limits for the flares during upsets or malfunctions. Therefore, the potential to emit (PTE) must be used in the modeling. The SO_2 PTE is 400 tons per hour of coal * 3.66% S coal * 64/32 = 29.28 tons per hour SO_2. Assuming that all the sulfur is converted into SO_2 is appropriate because IDEM admits that "SO2 emissions are merely a function of the amount of sulfur compounds in the gases vented to the flare and are unrelated to flare design." TSD at pdf page 645.

Response 7: See Response 5 under the Sierra Club comments regarding consideration of upsets and malfunctions in calculating PTE and modeling impacts. Also, regarding permit limits, the draft permit contains several operating requirements regarding flare minimization and flare best practices which are applicable at all times, including upsets and malfunctions.

Comment 8: As to emissions during shutdown, the PTE used in modeling is based on assumption of only 15 shutdowns using the flare per year. However, there is no permit requirement limiting IG to 15 shutdowns per year. Therefore, the PTE is actually 373.2 based on 8760 hours per year.

Response 8: See Response to U.S. EPA Comment 6.

Comment 9: In addition, the draft permit does not contain any enforceable 1-hour averaging time emission limits for any other emission units. Therefore, the modeling must use 1-hour averaging time PTE. In the SO_2 modeling, according to the shreadsheet submitted to IDEM under a September 29, 2011 cover letter, the modeling used a SO_2 emission rate of 0.00009 lb/hr for the emergency diesel engines in the normal operations with engines scenario, 0.005 in the normal operations / black start combo and 0.0006 in the normal ops combo scenario. The modeling appears to have included no emissions from the engines for the worst case black start combo scenario. We do not know where these emission rates came from and do not know why different values where used in the three scenarios with emission rates. IDEM needs to explain why three different values were used and also explain why the black start combo scenario assumes no emissions but the normal operations / black start combo includes emissions from the diesel engines. However, IDEM lists the permitted PTE of the emergency generator diesel engines as 0.015 lb/hr. TSD at pdf page 427, 363. Thus, the modeling must use 0.015 lb/hr in all scenarios.

The same is true for the firewater diesel pumps. In the SO_2 modeling, according to the shreadsheet submitted to IDEM under a September 29, 2011 cover letter, the modeling used a SO_2 emission rate of 0.00004 lb/hr for one scenario, 0.002 for another, 0.00025 for a third and no emissions for the "worst case black start" scenario. We do not know where these values came from, why different values were used in different scenarios and why no emissions were assumed for the "worst case black start" scenario. However, IDEM lists the permitted PTE of the firewater diesel pumps as 0.0061 lb/hr. TSD at pdf page 431, 363. Thus, the modeling must use 0.0061 lb/hr in all scenarios.

Response 9: The emissions rates listed by the commenter are for emergency generators and emergency fire water pumps which will only be operated in non-emergency use for readiness testing and maintenance. This will occur for 1 hour per week for each engine, and is limited by permit condition D.9.4 (e) which restricts each engine's operation to 52 hours per year of non-emergency operation. Because these sources operate intermittently and only briefly, their emissions rates for modeling purposes vary depending on the averaging time of the standard being modeled:

- Modeling for a 3 hr standard assumed each engine was tested for 1 hr resulting in an average emissions rate for the period 1/3rd the single hourly emission rate (1 hr of emissions divided by 3 hours of the standard).
- Modeling for a 24 hr standard used 1/24th the single hourly emissions rate.
- Annual modeling emissions rate assumed 52 hours of operations divided by 8760 hrs per year.

Regarding startups, no emergency engine testing was assumed for modeling scenarios covering only startups. Therefore, permit condition D.9.5 prohibits testing of these units during startups. However, for some pollutant modeling runs, IG modeled the combined worse case emissions of multiple operating modes to help limit the total number of modeling runs needed. For example, for modeling scenarios such as "normal operations/black start" emissions rates for emergency engines were included as part of normal operations, although they were excluded in a modeling run that only addresses startup.

The 1 hour NAAQS modeling (SO_2 and NOx) was treated slightly differently than the other averaging periods and according to guidance in a U.S. EPA OAQPS March 1, 2011 memorandum from Tyler Fox ("Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard"). The memorandum provides additional clarification regarding application of Appendix W modeling which applies to both NO_2 and SO_2 1-hour standards. The memo addresses emission scenarios concerning intermittent emissions from emergency generators or startup/shutdown operations. Page 8 of the memo starts the discussion on the "Treatment of Intermittent Emissions". Below are some excerpts from that memo:

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> *EPA's guidance in Table 8-2 of Appendix W involves a degree of conservatism in the modeling assumptions for demonstrating compliance with the NAAQS by recommending the use of maximum allowable emissions, which represents emission levels that the facility could, and might reasonably be expected to, achieve if a PSD permit is granted. <u>However, the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emission scenarios. The potential overestimation in these cases results from the implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions based on the specific hours on specific days of each of the years associated with the modeled design value based on the form of the hourly standard.</u> In fact, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact that outliers in the distribution might have on the design value. <u>The February 9, 2010, preamble to the rule promulgating the new 1-hour NO_2 standard stated that "it is desirable from a public health perspective to have a form that is reasonably stable and insulated from the impacts of extreme meteorological events." 75 FR 6492.</u> Also, the Clean Air Science Advisory Committee (CASAC) "recommended a 98th-percentile form averaged over 3 years for such a standard, given the potential for instability in the higher percentile concentrations around major roadways." 75 FR 6493.*

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> *Given the implications of the probabilistic form of the 1-hour NO_2 NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations. EPA believes that existing modeling guidelines provide sufficient discretion for reviewing authorities to exclude certain types of intermittent emissions from compliance demonstrations for the 1-hour NO_2 standard under these circumstances.*

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> *Another approach that may be considered in cases where there is more uncertainty regarding the applicability of this guidance would be to model impacts from intermittent emissions based on an average hourly rate, rather than the maximum hourly emission. For example, if a proposed permit includes a limit of 500 hours/year or less for an emergency generator, a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760. This approach would account for potential worst-case meteorological conditions associated with emergency generator emissions by assuming continuous operation, while use of the average hourly emission represents a simple approach to account for the probability of the emergency generator actually operating for a given hour. Also note that the contribution of intermittent emissions to annual impacts should continue to be addressed as in the past to demonstrate compliance with the annual NO_2 standard.*

Memorandum from Tyler Fox, Leader, EPA Air Quality Modeling Group, to Regional Air Division Directors, “Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard” (March 1, 2011). Thus, consistent with the guidance outlined above, for emergency engines permitted with an operating limit of 52 hours per year, the 1-hr SO_2 and NOx modeling used an average annual emissions rate (ie: 52 hrs of emissions divided by 8760 hrs/year).

Comment 10: Furthermore, the PTE and emissions used for the annual averaging time modeling for the emergency diesel generators and firewater pumps is limited to 52 hours based on the permit condition limiting these emission units to 52 hours of non-emergency operations per year. However, there is no exemption to PSD prohibition on violations of NAAQS to “emergency.” This is because air pollution is very dangerous and even deadly so IG’s understanding of an emergency does not permit it to release pollution that can injury or even kill innocent people. Thus, unless the permit contains a permit condition that absolutely limits operations of the emergency diesel generators and fire water pumps, the modeling has to be based on 8760 hours per year rather than 52 hours per year.

Response 10: The emergency diesel generators and firewater pumps will only be in operation on an intermittent basis. The March 01, 2011, Tyler Fox, U.S. EPA memorandum addresses this issue. See Response 9 under Sierra Club comments. In addition, U.S. EPA has offered guidance on how to calculate PTE for emergency generators used to provide back-up power when electric power from the local utility is interrupted. See Sept. 6, 1995 Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards on Calculating Potential to Emit (PTE) for Emergency Generators at 2-3.

Among other things, the Seitz Memo explains that "EPA has determined that a reasonable and realistic "worst-case" estimate of the number of hours that power would be expected to be unavailable from the local utility may be considered in identifying the "maximum capacity" of such generators for the purpose of estimating such generators PTE. Consequently, EPA does not recommend the use of 8760 hours per year (i.e., full-year operation) for calculating the PTE for emergency generators. Instead, EPA recommends that the potential to emit be determined based upon an estimate of the maximum amount of hours the generator could operate, taking into account (1) the number of hours power would be expected to be unavailable and (2) the number of hours for maintenance activities." Seitz Memo at 3. EPA's guidance provides for estimates "made on a case-by-case basis where justified by the source owner or permitting authority (for example, if historical data on local power outages indicate that a larger or smaller number would be appropriate)." Id. Thus, EPA's guidance makes it clear that Sierra Club is incorrect to suggest that the PTE for the IG emergency generators "be based on 8760 hours per year."

Here, 52 hours is considered a reasonable and realistic worse-case assumption. This allows for weekly maintenance and readiness testing of the each of these emergency engines. Regarding the emergency generators, given the specifics of this project, it is not necessary to additionally include any expected hours of predicted power interruption. This is because IG's power will come from its own steam turbine power generation. In the event of loss of IG's steam turbine, power can be supplied by the external power grid. In the event of loss of the external power grid, IG can run independently on the steam turbine generator. The emergency diesel generators will only be needed in the extremely unlikely double contingency emergency where IG loses both power sources at the same time. Regarding the emergency fire water pumps, outside of readiness/maintenance testing, these also will only be operated in the extremely unlikely event of a fire. Such an event is not expected and should not be considered in estimating reasonable and realistic facility PTE.

Comment 12: The September 29, 2011 spreadsheet also indicates that the wrong stack parameters may have been used in the modeling for the normal operations of the hydrocarbon flare. Again, we cannot be certain because we do not have the modeling. The spreadsheet indicates that the modeling used the stack height and stack diameter of the acid gas flare, that is 215 ft and 0.30 ft respectively, for the hydrocarbon flare during normal operations (pilot) when the actual stack height and stack diameter should be 292 ft and 16.89 ft. In addition, the spreadsheet claims that the temperature and exit velocity for the hydrocarbon flare are the same whether it is just burning natural gas in the pilot or burning methanol during gasifier start-up. This does not seem physically possible. Therefore, these values must be corrected if they are wrong in all of the modeling for all of the pollutants, the modeling re-run and a new public comment period held.

Response 12: The spreadsheet does indicate the hydrocarbon flare does have the same stack height and stack diameter as the acid gas flare during <u>normal operations</u>. The differences occur during different operating modes for the flares. Flares are different than normal stacks in that their pollutants are not released from a contained stack, but rather are emitted from the top of an open flame which is external to, and on top of, the flare stack. For flares, the emissions plume starts above the flame. Therefore, to properly account for this in the modeling, an effective stack height representing the top of the flame should be used in the model. Also, when the plume develops above the flame it may have a significantly different diameter than the actual flare stack diameter. Therefore, an effective diameter is estimated and input into the model.

There is a procedure U.S. EPA has published in the SCREEN 3 Model User's Guide (U.S.

EPA OAQPS, September 1995) to calculate effective stack parameters. The SCREEN model, and its methodology, calculates effective release height and effective release diameter based on the total heat release of the flared gases. These calculations (explained further in IG's application beginning on page 6-5) result in larger flaring heat releases with larger stack tip flames being modeled with correspondingly larger effective stack heights and diameters than flares in "normal" pilot mode.

These effective stack parameters and the resulting buoyancy flux estimate are expected to give reasonable final plume rise estimates for flares.

Comment 13: IDEM IMPROPERLY FAILED TO CONDUCT AN AMBIENT IMPACT ANALYSIS FOR OZONE

The Clean Air Act requires that new major sources of pollution demonstrate that they will not cause or contribute to a violation of any ambient air quality standard. The current ambient air quality standard for ozone is 75 parts per billion. Ozone causes a variety of adverse impacts including asthma attacks and decreased yields of crops such as corn and soybeans.

Response 13: See response to U.S. EPA Comment 1.

Comment 14: IG and IDEM made no attempt to establish whether the proposed IG facility will cause or contribute to a violation of the ozone ambient air quality standard. There are no ozone monitors in Spenser County and IDEM failed to require IG to conduct pre-construction ozone monitoring so we do not know how bad the ozone problem is even before adding in IG's addition pollution. However, what we do know is that Clark County's ozone level for 2009-2011 is 75.3 parts per billion. *See* Ex. 1, 2, and 3. Thus, Clark County is already exceeding the ozone ambient air quality standard before we adding in pollution from Indiana Gasification. IG will surely contribute to this problem. The monitor in New Albany at the Green Valley Elementary School was at 80 parts per billion, well above the 75 parts per billion standard, in 2011. *See* Ex. 3. Scientific research has shown that children are especially susceptible to injury from ozone pollution because their lungs are still developing and they are generally more activity outside than adults. The monitor in Greene County had a three year average in 2009-2011 of 74 parts per billion. See Ex. 1, 2, and 3. Though just barely below the ambient standard, Indiana Gasification and IDEM did not use a computer model to see if the pollution from Indiana Gasification would send Greene County over the limit. IDEM started operating a new monitor in Knox County at the Southwest Purdue Agricultural Center in Vincennes in 2011. It monitored at 77 parts per billion, above the 75 parts per billion standard. The monitor in Perry County had a reading of 74 parts per billion in 2011, again just barely below the standard. On the other hand, Posey County had a reading of 76, Boonville High School in Warrick County had a reading of 75, and Evansville had a reading of 77 parts per billion in 2011, exceeding the standard.

Before IDEM allows additional ozone forming pollution that can cause asthma attacks, decreased crop yields and other problems, they should require Indiana Gasification to use a state of the art computer model such as CAMx to establish that the additional pollution from Indiana Gasification will not cause or contribute to violation of the ozone ambient air quality standard.

Response 14: See Response to U.S. EPA Comment 1 and Response 38 under comments received by the Public.

Comment 15: IDEM claims that VOCs are below the significant emission rate. TSD pdf page 812. However, NO_2 is also an ozone precursor. IG is over the 100 TPY significant level for NO_2. Therefore an ambient impact analysis is required for ozone.

IDEM claims:

An air quality analysis is not performed for VOCs because they are photochemically reactive. Photochemical models like UAM-V are used in regulatory or policy assessments to simulate the impacts from all sources by estimating pollutant concentrations and deposition of both inert and chemically reactive pollutants over large spatial scales. Currently, U.S. EPA has no regulatory photochemical models which can take into account small spatial scales or single source PSD modeling for ozone. AERMOD is not a photochemical model.

This is not true. To begin with, at a minimum, Appendix W requires that IDEM consult with EPA and obtain EPA's approval of the modeling approach to addressing ozone. Furthermore, it is now clear that there are models that are capable of modeling a PSD source's impact to ozone. This is demonstrated in Sierra Club's Petition for Rulemaking to Designate Air Quality Models to use for PSD Permit Applications with Regard to Ozone and $PM_{2.5}$, the December 8, 2011 letter providing additional documents which support the petition, and US EPA's January 4, 2012 response to the petition. We are providing you with these documents which we hereby incorporate herein by reference.

Response 15: See response to U.S. EPA Comment 1. Also, in reading the January 4, 2012 U.S. EPA response letter cited by the Commenter, it is not "...now clear that there are models that are capable of modeling a source's impact to ozone." In its review of U.S. EPA's response letter, IDEM was unable to find any information regarding a model with this capability. What this letter actually says, on pages 2 and 3, follows:

"However, recent advances in photochemical modeling science suggest that it may now be reasonable for the EPA to provide more specific, generally-applicable guidelines that identify particular analytical techniques or models that may be used under specific circumstances for assessing the impacts of an individual source on ozone concentrations and on the secondary formation of $PM_{2.5}$. These advances have resulted in <u>some methods that may allow</u> for tracking the formation and transport of ozone and secondary $PM_{2.5}$ impacts from specific emissions sources and calculating the contribution of sources and precursors to ozone and $PM_{2.5}$ at individual receptor locations. In fact, the EPA engaged the modeling community on these developments at the 9th Conference on Air Quality Modeling in October 2008 by devoting a session to photochemical modeling with instrumented techniques such as "source apportionment" to promote understanding of their emerging capabilities by the regulatory modeling community.

"The EPA has scheduled the 10th Conference on Air Quality Modeling for March 13-15, 2012, in Research Triangle Park, North Carolina. We intend to issue the Federal Register notice announcing the conference in early 2012 which will outline the agenda with the topic of chemistry models and related techniques for addressing impacts of ozone and secondary $PM_{2.5}$ being a major session and focus of the EPA's efforts to engage the regulatory modeling community.

<u>This modeling conference will serve as the initial venue for gaining public input to begin the rulemaking process of updating Appendix W.</u> As was the case in promulgating new dispersion models (CALPUFF and AERMOD) in 2003 and 2005, the EPA expects to form a similar workgroup to conduct the necessary evaluations and inter-comparisons of technical approaches and models to inform the rulemaking process and provide sufficient technical justification for those technical approaches and/or models that are ultimately determined to be appropriate for incorporation into Appendix W.

This workgroup will be critical in informing the rulemaking process, and the reports and other findings will be made publicly available and be central to discussion at future modeling conferences. Consistent with the past practice described earlier, the EPA expects such discussion to occur at the 11 th Conference on Air Quality Modeling with consideration of the specifics of the EPA's proposed rule to update Appendix W.

"Furthermore, as this complex rulemaking process proceeds, the EPA will be taking additional steps in the interim to enhance understanding of acceptable techniques for evaluating impacts of individual source emissions on ozone concentrations and secondary $PM_{2.5}$ formation."

(Emphasis added). In summary, IDEM did use output from a regional model to perform the ozone analysis (see response to U.S. EPA Comment 1). However, it is clear from the above paragraphs, that while there may be some methods available to track formation, these techniques have not yet been evaluated or finalized and no models exist for this purpose. The above states that the March 2012 10th Conference on Air Quality Modeling will serve as the initial venue to begin the process of updating Appendix W. While it would be desirable to have a model available now for this purpose, it will be years before such a model will be available.

Comment 16: THE NOx AMBIENT IMPACTS ANALYSIS WAS INADEQUATE

The TSD claims that the modeling demonstrated that IG has a modeled impact of 7.4 ug/m3 which is below the significant impact level (SIL) of 7.55 ug/m3 for the 1-hour NOx NAAQS. TSD at pdf page 814. Thus, the TSD claims that a cumulative NOx analysis is not required. This is incorrect.

Response 16: For the reasons discussed in response to Sierra Club Comment 2 with respect to SO_2, the NOx ambient impacts analysis was appropriate and correct.

For the 1-hour SO_2 and 1-hour NO_2 standards, U.S. EPA provided an interim SIL. The interim SIL for NO_2 is 4 ppb (7.55 µg/m^3). See Memorandum from Anna Marie Wood, Acting Director, U.S. EPA Air Quality Policy Division, to Regional Air Division Directors, "General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level" (June 28, 2010) ("NO_2 SIL Guidance"); see also Memorandum from Tyler Fox, Leader, U.S. EPA Air Quality Modeling Group, to Regional Air Division Directors, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (March 1, 2011).

U.S. EPA explained the basis for this SIL value:

> We derived this interim 1-hour NO_2 SIL by using an impact equal to 4% of the 1-hour NO_2 NAAQS (which is 100 ppb). We have chosen this approach because we believe it is reasonable to base the interim 1-hour NO_2 SIL directly on consideration of impacts relative to the 1-hour NO_2 NAAQS. In 1980, we defined SER for each pollutant subject to PSD. For PM and SO_2, we defined the SER as the emissions rate that resulted in an ambient impact equal to 4% of the applicable short-term NAAQS. The 1980 analysis focused on levels no higher than 5% of the primary standard because of concerns that higher levels were found to result in unreasonably large amounts of increment being consumed by a single source. Within the range of impacts analyzed, we considered two factors that had an important influence on the choice of de minimis emissions levels: (1) cumulative effect on increment consumption of multiple sources in an area, each making the maximum de minimis emissions increase; and (2) the projected consequence of a given de minimis level on administrative burden.
>
> As explained in the preamble to the 1980 rulemaking and the supporting documentation, EPA decided to use 4% of the 24-hour primary NAAQS for PM and SO_2 to define the significant emissions rates (SERs) for those pollutants. It was noted that, at the time, only an annual NO_2 NAAQS existed. Thus, for reasons explained in the 1980 preamble, to define the SER for NOx emissions we used a design value of 2% of the annual NO_2 NAAQS. Looking now at a short-term NAAQS for NO_2, we believe that it is reasonable as an interim approach to use a SIL value that represents 4% of the 1-hour NO_2 NAAQS.

NO_2 SIL Guidance at 12-13 (internal citations omitted). The SIL was made available to States with U.S. EPA-approved implementation plans containing a PSD program to use at their discretion. NO_2 SIL Guidance at 10 ("EPA intends to implement the interim 1-hour NO_2 SIL contained herein under the federal PSD program and offers states the opportunity to use it in their PSD programs if they choose to do so."). IDEM agrees with U.S. EPA's basis for this interim SIL value of 4 ppb, and the SIL was implemented in accordance with the NO_2 SIL Guidance. Thus, although the SIL for NO_2 is not incorporated into Indiana's SIP, it does not need to be in order for IDEM to utilize this screening tool.

Consistent with U.S. EPA's guidance, IDEM used the maximum 1st highest 1-hour concentration averaged over 5 years for comparison to the 1-hour NO_2 SIL of 4 ppb (7.55 $\mu g/m^3$).

Comment 17: To begin with, the SIL is not in Indiana's SIP. Therefore, IDEM cannot rely on it to issue a Title V permit. Furthermore, IDEM has offered nothing in the record to support the use of a SIL in generally or a 7.55 ug/m3 1-hour SO_2. Thus, IDEM cannot rely on this SIL.

Response 17: Assuming the commenter is referring to the use of a 7.55 ug/m3 1-hour NO_2 SIL, this issue is addressed in the response to Sierra Club Comment 16. See the response to Sierra Club comment 2 for a justification of the 1-hour SO_2 SIL.

Comment 18: Also, even if the SIL was permissible, IDEM averaged five years of impacts and compared the average to the SIL. The proper analysis would be where any one year exceeded the SIL. While, as explained above, we do not have the modeling files because IDEM failed to make them available at the library, we believe, based on the average being so close to the SIL, that at least one year was above the SIL. Therefore, a cumulative impact analysis is required followed by an additional public comment period.

Response 18: For the same reasons discussed in response to Sierra Club Comment 2 with respect to SO_2, the NOx ambient impacts analysis was appropriate and correct. IDEM modeled NO_2 in accordance with U.S. EPA guidance. See Memorandum from Anna Marie Wood, Acting Director, U.S. EPA Air Quality Policy Division, to Regional Air Division Directors, "General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level" (June 28, 2010) ("NO_2 SIL Guidance"); Memorandum from Tyler Fox, Leader, U.S. EPA Air Quality Modeling Group, to Regional Air Division Directors, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (March 1, 2011). Specifically, the NO_2 SIL Guidance provides:

In this guidance, EPA recommends an interim 1-hour NO_2 SIL value of 4 ppb. To determine initially whether a proposed project's emissions increase will have a significant impact (resulting in the need for a cumulative air quality analysis), this interim SIL should be compared to either of the following:

- The highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data; or

- The highest modeled 1-hour NO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data.

NO_2 SIL Guidance at 12 (emphasis added). Because representative nearby National Weather Service data was available, IG used the first option listed above rather than collect 1 year of site-specific meterological data. Following this guidance, IDEM used the maximum 1st highest 1-hour concentration at each receptor averaged over 5 years for comparison to the 1-hour NO_2 SIL of 4 ppb (7.55 $\mu g/m^3$).

Comment 19: In addition, the draft permit does not contain any enforceable 1-hour averaging time emission limits. Therefore, the modeling must use 1-hour averaging time PTE. In the NOx modeling, according to the spreadsheet submitted to IDEM under a September 29, 2011 cover letter, the modeling used an NOx emission rate of 0.09 lb/hr for the emergency diesel engines. We do not know where this value came from. However, IDEM lists the permitted PTE of the emergency diesel engines as 14.58 lb/hr. TSD at pdf page 427, 363. Thus, the modeling must use 14.58 lb/hr rather than 0.09 lb/hr.

The same is true for the firewater diesel pumps. In the NOx modeling, according to the spreadsheet submitted to IDEM under a September 29, 2011 cover letter, the modeling used a NOx emission rate of 0.02 lb/hr for the emergency diesel engines. We do not know where this value came from. However, IDEM lists the permitted PTE of the emergency diesel engines as 3.131 lb/hr. TSD at pdf page 431, 363. Thus, the modeling must use 3.131 lb/hr rather than 0.02 lb/hr.

Response 19: See response to Sierra Club Comment 9, which discusses the same issue regarding SO_2 emissions from these emergency engines. In summary, this emergency equipment will only operate intermittently and briefly. Therefore, their emissions rate for modeling purposes varies depending on the averaging time of the standard being modeled.

Comment 20: Furthermore, the PTE and emissions used for the annual averaging time modeling for the emergency diesel generators and firewater pumps is limited to 52 hours based on the permit condition limiting these emission units to 52 hours of non-emergency operations per year. However, there is no exemption to PSD prohibition on violations of NAAQS to "emergency." This is because air pollution is very dangerous and even deadly so IG's understanding of an emergency does not permit it to release pollution that can injury or even kill innocent people. Thus, unless the permit contains a permit condition that absolutely limits operations of the emergency diesel generators and fire water pumps, the modeling has to be based on 8760 hours per year rather than 52 hours per year.

Response 20: See response to Sierra Club Comment 10 regarding U.S. EPA guidance on estimating PTE for emergency equipment.

Comment 21: The September 29, 2011 spreadsheet also indicates that the wrong stack parameters may have been used in the modeling for the normal operations of the hydrocarbon flare. Again, we cannot be certain because we do not have the modeling. The spreadsheet indicates that the modeling used the stack height and stack diameter of the acid gas flare, that is 215 ft and 0.30 ft respectively, for the hydrocarbon flare during normal operations (pilot) when the actual stack height and stack diameter should be 292 ft and 16.89 ft. In addition, the spreadsheet claims that the temperature and exit velocity for the hydrocarbon flare are the same whether it is just burning natural gas in the pilot or burning methanol during gasifier start-up. This does not seem physically possible. Therefore, these values must be corrected if they are wrong in all of the modeling for all of the pollutants, the modeling re-run and a new public comment period held.

Response 21: See response to Sierra Club Comment 12 for an explanation of the basis for flare modeling parameters.

Comment 22: Finally, the TSD indicates that a Tier II 80% conversion of NO to NO_2 was assumed based on the March 1, 2011 Tyler Fox memorandum. TSD pdf page 814. IDEM would need to obtain US EPA approval to use this 80% conversion of NO to $NO_{2.}$ There is no indication that IDEM obtained it. Furthermore, IDEM would need to give a valid justification for the use of this approach. IDEM has offered none.

Response 22: U.S. EPA has allowed the use of the 0.80 NO to NO_2 ambient ratio as a default without prior approval. According to the March 1, 2011, Memorandum from Tyler Fox, it states on page 5:

"In order to ease the burden on permit applicants in addressing the need to demonstrate compliance with the 1-hour NO_2 NAAQS, as well as the burden on the permitting authority in reviewing such applications, we offer additional discussion and recommendations in relation to the use of Tier 2 and Tier 3 options. Specifically, we recommend the following:

- Use of 0.80 as a default ambient ratio for the 1-hour NO_2 standard under Tier 2 without additional justification by applicants;"

(Emphasis added). Page 6 of the above memorandum further states – "We still do not consider 0.75 as an appropriate default ambient ratio for the 1-hour standard, but several references cite ambient ratios of about 0.80 for hourly NO_2/NOx (e.g., Wang, et al., 2011; Janssen, et al., 1991), and we believe it would be appropriate to accept that as a default ambient ratio for the 1-hour NO_2 standard." (Emphasis added).

Comment 23: THE AMBIENT IMPACT ANALYSIS FOR $PM_{2.5}$ IS INADEQUATE

IDEM acknowledges that it modeled a violation of the 24-hour $PM_{2.5}$ NAAQS to which IG is contributing. However, IDEM claims that IG can still obtain its PSD permit because the contribution from IG is below the SIL. To begin with, the SIL is not in Indiana's SIP. Therefore, IDEM cannot rely on it to issue a Title V permit. Furthermore, IDEM has offered nothing in the record to support the use of a SIL. Thus, IDEM cannot rely on this SIL.

Response 23: For an analysis of the appropriateness of use of SILs in PSD permitting, see responses to Sierra Club Comments 2 and 24.

For 24-hour and annual $PM_{2.5}$ standards, U.S. EPA published a final rule in the Federal Register on October 20, 2010. 75 Fed. Reg. 64,864 (Oct. 20, 2010). This rule codified the SILs in the federal PSD regulations at 40 C.F.R. § 52.21. In the preamble to the final rulemaking, U.S. EPA explained, "[t]he SILs for $PM_{2.5}$ are incorporated into the Federal PSD program as well as into the regulations for state-implemented PSD programs, although they are regarded as optional for State programs." 75 Fed. Reg. 64,864, 64,866 (emphasis added). The relevant SIL for the 24-hour averaging period is 1.2 ug/m^3 and for the annual averaging period is 0.3 ug/m^3. Id. As explained by U.S. EPA in the Final Rule, these values were derived by scaling the PM_{10} SIL values by the ratio of the $PM_{2.5}$ NAAQS to the PM_{10} NAAQS. Id. at 64890. Of the three methodologies originally proposed by U.S. EPA for setting the PM2.5 SIL values, the option chosen in the Final Rule resulted in the most stringent (lowest) SIL values. Id.

Indiana has put these same stringent SILs into an "Emergency Rule" – LSA Document #12-68(E), section 13(b) which supersedes 326 IAC 2-3-2(f). LSA Document #12-68(E) became effective on February 2, 2012, though the original "Emergency Rule" incorporating the $PM_{2.5}$ SILs into the Indiana Administrative Code (IAC) became effective on August 3, 2011. See "Emergency Rule" – LSA Document #11-447(E), section 13(b); see also "Emergency Rule" – LSA Document #11-680(E), section 13(b) (extending the PM2.5 emergency rule from November 2, 2011 to January 31, 2012). The SIL for $PM_{2.5}$ was implemented in accordance with LSA Document #12-68(E), section 13(b) and U.S. EPA's $PM_{2.5}$ rulemaking.

Commenter is incorrect in its claim that "IDEM acknowledges that it modeled a violation of the 24-hour $PM_{2.5}$ NAAQS to which IG is contributing." During the time of the two modeled NAAQS violations, IG's modeled contribution was merely 0.15 and 0.14 ug/m3, respectively, which results are well below the de minimis SIL value of 1.2 ug/m3. Air Quality Analysis, pages 6-7 of 49. Therefore, IDEM concluded "Even though the model predicts a NAAQS violation, IG was not significant at the same receptor and time period. Therefore, IG does not cause or contribute to a violation of the NAAQS." Id. (emphasis added). See also U.S. EPA Workshop NSR Manual (Draft 1990) at C.52 ("The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation."). Thus, consistent with U.S. EPA guidance, IDEM concluded that the proposed facility will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

Comment 24: Further, the use of SILs is illegal. We explained this in the Opening Brief of Sierra Club in Sierra Club v. United States Environmental Protection Agency, 10-1413 (D.C. Cir) which were are attaching as Exhibit 4 and hereby incorporating by reference.

Response 24: The arguments made by Sierra Club in its opening brief in Sierra Club v. United States Environmental Protection Agency regarding the legality of SILs have been repeatedly rejected by U.S. EPA and federal courts alike. U.S. EPA has long-approved the use of SILs, and challenges to the legality of SILs have been rejected by federal courts and the Environmental Appeals Board. See, e.g., Sur Contra La Contaminacion v. EPA, 202 F.3d 443, 448-49 (1st Cir. 2000) (upholding U.S. EPA's use of SILs to allow permit applicant to avoid full impact analysis); In re Prairie State Generation Company, 13 E.A.D. 1, 104-108 (Aug. 24, 2006) (same).

U.S. EPA's use of SILs is rooted in the *de minimis* exception observed in Alabama Power v. Costle, 636 F.2d 323, 360 (D.C. Cir. 1979). Historically, "EPA has allowed the use of several types of screening tools to facilitate implementation of preconstruction review process to reduce the permit applicant's burden and streamline the permitting process for *de minimis* circumstances. These tools include …SILs…." 75 Fed. Reg. 64,864, 64,866 (Oct. 20, 2010) (final rule establishing SILs for PM2.5). As explained in U.S. EPA's 1990 New Source Review manual:

> The EPA does not require a full impact analysis for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels, including Class I significance levels. However, the applicant should check with any applicable State or local PSD program requirements in order to determine whether such requirements may contain any different procedures which may be more stringent,

U.S. EPA NSR Workshop Manual (Draft 1990) at C.24-C.25. Thus, while IDEM has the authority to establish more stringent procedures (*i.e.,* not allow the use of screening tools in air quality modeling), IDEM—like U.S. EPA—permits the use of SILs. For a description of the status of Indiana's rulemaking to codify the SIL for $PM_{2.5}$ in Indiana's rules, see IDEM's response to Sierra Club Comment 23.

Comment 25: In addition, the $PM_{2.5}$ modeling failed to include all $PM_{2.5}$. First, it failed to include secondary $PM_{2.5}$, that is chemicals that are emitted from stacks and vents as $PM_{2.5}$ precursors and converted to $PM_{2.5}$ in the ambient air. Above, we explained how ozone impacts can be modeled for a single source. Those same documents establish that secondary $PM_{2.5}$ can also be modeled for a single source.

Response 25: See response to Sierra Club Comment 15. This same analysis, regarding U.S. EPA's January 4, 2012 response letter, applies to secondary $PM_{2.5}$.

Also, 40 CFR Part 51, Appendix W, Sec. 5.2.2.1.c provides the following for $PM_{2.5}$:

> Estimating the Impact of Individual Sources. Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the Regional Office to determine the most suitable approach on a case-by-case basis. . . .

Additionally, in a March 23, 2010 U.S. EPA guidance memorandum entitled "Modeling Procedures for Demonstrating Compliance with PM $_{2.5}$ NAAQS," U.S. EPA recognized that because secondary formation of $PM_{2.5}$ often contributes significantly to total ambient levels of $PM_{2.5}$, certain aspects of standard modeling practices used for PM-10 and other criteria pollutants may not be appropriate for $PM_{2.5}$. See Memorandum from Stephen D. Page, Director, U.S. EPA Office of Air Quality Planning and Standards, "Modeling Procedures for Demonstrating Compliance with $PM_{.5}$ NAAQS" (March 23, 2010) at 3-7.

IDEM has fully considered PM $_{\mathbf{2.5}}$ impacts from this project. In accordance with the foregoing U.S. EPA regulatory position, an analysis for $PM_{2.5}$ secondary formation can be found at pages 9-12 of 49 in the Air Quality Analysis for the permit.

Comment 26: Finally, the $PM_{2.5}$ modeling failed to include emissions from the barges and trains in the $PM_{2.5}$ NAAQS modeling. These sources should have been included the NAAQS modeling as nearby background sources.

Response 26: Regarding the appropriate sources to include in the NAAQS modeling inventory, U.S. EPA states:

> … Also, sources from which secondary emissions will occur as a result of the proposed source should be identified and evaluated for inclusion in the NAAQS inventory. While existing mobile source emissions are considered in the determination of background air quality for the NAAQS analysis (typically using existing air quality data), it should be noted that the applicant need not model estimates of future mobile source emissions growth that could result from the proposed project because the definition of "secondary emissions" specifically excludes any emissions coming directly from mobile sources.

NSR Workshop Manual (Draft, Oct. 1990) at C.34. Consistent with this, existing mobile source emissions are included in background for the modeling.

As part of the cumulative PSD analysis for the $PM_{2.5}$ 24-hour and annual NAAQS, representative background monitoring data in vicinity of the IG facility are included in the analysis to represent the ambient background $PM_{2.5}$ concentrations from sources not included in the regional modeling analysis, such as mobile emissions and smaller unpermitted sources.

There were six monitoring stations considered for use in the modeling analysis – including two in Kentucky and four in Indiana. Of those, the Owensboro monitoring station was chosen. It is located in the Wyndall Shopping Center, an area of commercial use in the suburban area of Owensboro. The Owensboro monitoring station is the most representative of the IG site based upon its proximity (9.7 miles south of the IG site, the closest of the stations evaluated), location type similarity (not urban), and there are no significant topographical features separating the site and monitoring station. Additionally, the 24-hour $PM_{2.5}$ design value of 26 micrograms per cubic meter (ug/m^3) for the Owensboro station is the highest of the three closest stations to the IG facility.

IG used the Owensboro background design values of 26 ug/m^3 and 12.2 ug/m^3 for the 24-hour and annual cumulative analysis, respectively. These conservative background values include existing mobile emissions.

Hazardous Air Pollutants (HAPs)

Comment 27: Since this facility unquestionably has the potential to emit HAPs in excess of major source HAP emission thresholds and the permit does not have enforceable limitations on the potential to emit that would ensure emissions remain below this threshold, IDEM cannot authorize construction of IG without issuing a MACT/NESHAP determination for all the MACT/NESHAP standards that IDEM claims are not applicable because IG is a minor source.

IDEM finds that the proposed plant would not be a major source of HAPs because potential emissions from these emission points would be less than the applicable thresholds of 25 tons per year in the aggregate for total HAPs and less than 10 tons per year for any single HAP. TSD at 9-11, Appendix A 2. Accordingly, the IDEM finds that the plant is not subject to the National Emission Standards for Hazardous Air Pollutants (“NESHAPs”), adopted by U.S. EPA under 40 CFR 63, that apply to major sources of HAPs. IDEM further fails to apply a case-by-case determination of maximum achievable control technology (“MACT”) pursuant to Section 112(g) of the Clean Air Act for those emission units at the facility that would not be subject to the NESHAP standards.
As demonstrated below, IDEM’s conclusions are erroneous and based on severely flawed and not adequately supported emission estimates for HAPs. The Draft Permit then

compounds these errors by failing to reflect the emission calculations in enforceable permit limits. When properly estimated, potential emissions of HAPs from the proposed facility exceed the major source thresholds for both single and total HAPs, making the proposed facility a major source of HAPs and requiring MACT for the sources.

Response 27: Absent controls and enforceable permit limits, the facility could have the potential to emit HAPs above the major source threshold of 25 tons/yr of total HAPs or above 10 tons/yr of any individual HAP. However, there are sufficient controls and enforceable limits to assure the facility will be a minor source of HAPs. The necessary limitations on HAP emissions appear in permit condition D.4.11. As indicated in the response to EPA Comment 9, these provisions are being revised to assure the effectiveness of these requirements. As revised, the condition includes specific practically enforceable limits on the emissions of methanol and total HAPs from the AGR vents. These limits ensure that the limited AGR PTE and the PTE of all the other HAP sources in total will be less than 10 tpy for any one HAP and 25 tpy for all HAPs.

The most significant single HAP from this facility is methanol, which is predominantly emitted from the AGR vents. It should be noted at the outset that all HAPs evaluations for the AGR vent are made assuming that the entire CO_2 stream is directed to the vent during the full year, with none to the pipeline (i.e., resulting in 6,430,000 tpy of CO_2 emissions from the AGR vent). In fact, the figures used are allowed only during year 2 of operation. Beginning in year three, the AGR vent will be allowed only 1,290,000 tpy of CO_2, and actual HAPs emissions from the vent would therefore be significantly less. Absent controls, the two AGR vents' methanol emissions could be more than 10 tons/yr. However, the permit requires that the AGR vent gas streams be controlled with a regenerative thermal oxidizer (RTO) with total methanol emissions from both AGR's limited to less than 9 tons/yr. RTOs are very effective in controlling organic HAPs and are expected to be 99% effective in controlling methanol. The permit requires performance testing of the RTOs to verify compliance with the emissions limitation and ongoing parametric monitoring of the RTO temperature to assure continuous compliance. Thus, the facility's most significant HAP stream is well controlled and will be assured to emit less than 9 tons/yr of the single largest facility HAP, methanol. The PTE of the other facility methanol emissions sources is no more than 0.66 tons/yr. The other facility methanol emission sources are the methanol tankage, which has emissions controlled and regulated by NSPS Kb, and methanol piping equipment leaks, which will be controlled through a formal Leak Detection and Repair program, specified in permit condition E.6.1. Therefore, total facility-wide methanol emissions will be less than the major source threshold of 10 tons/yr.

The only other single HAP which has the potential to be emitted in levels greater than 10 tons/yr if uncontrolled is Carbonyl Sulfide (COS). The only significant source of COS emissions is the AGR vents which may contain up to 2 lb/hr of COS in each of the two vents, for a combined total of about 17 tons/yr in these vents before they are controlled by the RTOs. The regenerative thermal oxidizers are expected to be 98% effective in controlling the COS, with a resultant emissions rate of COS of well below 10 tpy. The permit conditions D.4.17 and D.4.20 assure that the RTO will be operating properly whenever the AGR vents are in operation.

The permit limits the total HAPs from the AGR/RTO vents. As described in Response to EPA Comment 9, this limit is being lowered slightly to 17.0 tons/yr.

As detailed in the response to the EPA Comment 9, the permit conditions for the testing and reporting of HAPs from the AGR/RTO vents are being modified. The testing of the RTO vent under permit condition D.4.19(d) has been expanded to address other HAPs that may be emitted and the compliance demonstration for the total HAPs limit on the AGR/RTO vents has been specified in permit condition D.4.11

Plantwide, all other HAP pollutants are emitted in very small amounts, totaling less than 2.1 tons/yr. These other HAPs are either fugitive emissions addressed by the LDAR program in permit section E.6 or they are byproducts of combustion (e.g. formaldehyde and hexane) and require no additional controls. Consequently, the facility total HAPS emissions are limited to less than 10/25 tpy by the limits on the AGR/RTO vents. Thus, the facility will not be a major source of HAPs.

Comment 28: THE TSD INCORRECTLY ASSUMED VARIOUS EMISSION UNITS HAVE ZERO HAPS EMISSION

The TSD assumes that the syngas hydrocarbon flare, the acid gas flare, the emergency diesel generators and the emergency firewater pumps each have a PTE of 0 TPY HAPs. TSD at 9. This is not correct.

To begin with, IDEM assumes that the uncontrolled PTE from the syngas hydrocarbon flare, acid gas flare, emergency diesel generator and emergency firewater engine are all zero. TSD App A at 1. This is obviously incorrect. It is well documented that diesel fired generators emit hazardous air pollutants. *See e.g.* AP-42 at 3.3-6 - 3.3-7, 3.4-7. IDEM provides no information on how it calculated that HAP emissions from the emergency diesel generators and emergency firewater engines are zero. *See* TSD at pdf page 427 - 430 (showing greenhouse gas and criteria pollutants but not HAP emission calculations).

It does seem that IDEM based its HAPs emission calculations on limited hours of operations for the diesel fire water pump and diesel emergency generator. However, these emission units are only limited to 52 hours per year of non-emergency operations. This is not a valid restriction on operations because there is no exemption from PTE definition for emergency operations. Obviously, operation of the emergency diesel engines and firewater pumps is a realistic worst case scenario. If it was not realistic that these units would operate during emergencies, IG would not have them. Therefore, the PTE has to be based on 8760 hours per year.

Response 28: This comment addresses HAP emissions from three sources: the syn gas flare, the acid gas flare and the emergency engines. The response addresses each in that order:

Syn Gas Flare: The permit analysis considered and quantified flare emissions during flare standby, flaring at start up and flaring during gasifier shutdown. When in stand-by, the flare pilot burns either natural gas or SNG. The emissions analysis uses the AP-42 HAP emissions factors for natural gas and assumes the pilots operate at all times. SNG and natural gas are predominantly methane and contain other trace components. SNG combustion is expected to have fewer total HAP than natural gas combustion. (See the response to Sierra Club comment 29). The use of the natural gas emissions factors for natural gas is appropriate and, for SNG combustion, is conservative. During gasifier start-up, the flare receives syngas from the gasifier. The gasifiers are always started with methanol as feedstock. Startup begins with heating the gasifier to its operating temperature with the preheat burner and feed to the gasifier does not occur until the gasifier is hot enough to convert the methanol to CO, H_2, CO_2 and a trace amount of methane. The combustion of this clean mixture does not result in HAP emissions beyond those of the pilot burner that is operating during start up. A small amount of coal/coke derived syngas will be vented to the flare during the final vessel depressurization during planned shutdowns. The total quantity of these gases vented to the flare is very small. Also, these flared gases, are products of the gasification process and are predominantly CO, CO_2 and H_2. These compounds would combust in a flare extremely cleanly, with negligible HAP formation.

Nevertheless, as further verification of their insignificant magnitude, IDEM has, for informational purposes, estimated worse case HAPs emissions for syngas combustion during shutdowns using metal HAP emissions factors from a recently permitted syngas facility (the Edwardsport IGCC facility, Permit No. 083-23529-00003), August 2006 permit application, Table 2-19.), the HCl concentration maximum provided by the gasifier manufacturer and EPA's organic HAPs emissions factors for natural gas. Using these conservative factors, total HAPs from combustion of shutdown flare venting amounts to less than 0.005 tons/yr.

Acid Gas Flare: As with the syn gas flare, the HAP PTE analysis includes emissions of the pilot on the flare operating 8760 hours a year. The acid gas flare has no other emissions during startups or planned shutdowns.

Emergency Engines: HAPs from the diesel engines (firewater pumps and emergency engines) are extremely small. For informational purposes, total emergency engine HAPs emissions using EPA's diesel fuel internal combustion HAP emissions factors during permitted operation are 0.002 tons/yr.

Regarding the appropriate consideration of malfunction and emergency operation when calculating PTE, see response to Sierra Club Comments 5 and 10.

The emission calculations for all three sources described above are set out in the attached tables in 30464 ATSD - Appendix A.

Comment 29: IDEM used AP-42 rather than an enforceable emission limit for the total VOC HAPs. *See e.g.* TSD at pdf page 403. EPA has consistently rejected this approach. IDEM provides no information about where it obtained the mercury emission factor. *Id.* Agencies are not allowed to use random numbers to calculate PTE without an citation to where the mercury emission factor came from. Thus, IDEM significantly underestimated the HAPs PTE.

Response 29: Except for the emergency engines and fire pumps, all the facility fired equipment operates on natural gas or SNG. Natural gas and SNG are both primarily methane with other trace components. Natural gas is more likely to have the precursors of HAPs than SNG, though still in very small quantities. While natural gas contains some light hydrocarbons that remain from the separation of liquids and gases during its extraction and production, the methane in SNG is chemically built from CO, H_2 and water in reactions that do not produce higher molecular weight hydrocarbons. The organic HAP emissions attributed to natural gas are the dominant HAPs and the other HAPs are trivial by comparison. It is therefore appropriate for natural gas and conservative for SNG to use the standard emissions factors for natural gas to determine such small levels of HAPs from combustion.

IDEM and EPA have used AP-42 factors for natural gas consistently in a wide range of HAP emissions determinations. (This is discussed further in the response to Sierra Club comment 34) Further, when the HAPs PTE of a source is very small and the total HAPs PTE is still below the major source limit, unit by unit limits on trivial sources of HAPs that reflect their PTE for HAPs are not appropriate.

The basis for the site specific emissions factor for mercury is presented in the IDEM pdf page 489 of 880. As noted on that page, the site specific mercury emissions factor for SNG of 1.65x10-6 lb mercury per MMBtu (HHV) is based on a reported maximum mercury content of Indiana coal, assuming that virtually all of that mercury ends up in the syngas and 98.6% of the mercury is removed in sulfided carbon beds which treat the syngas before methanation (the process that converts it to SNG). Average reported mercury levels in Indiana coal is about 1/4th the assumed level. Therefore, the mercury emissions estimate is conservative.

Comment 30: **IDEM FAILED TO CONSIDER SSM WHEN CALCULATING PTE FOR HAPS**

For the acid gas flare and hydrocarbon flare, IDEM completely ignored HAPs emissions when the flares are flaring process gases during upsets and malfunctions even though IDEM acknowledges that this does happen. *See* TSD at pdf page 363, 403. Rather, the only emissions considered are from the pilot in the flare or from startup on methanol. *Id.* IDEM must calculate PTE to include flaring of process gases during upsets and malfunctions.

Response 30: As explained in the response to Sierra Club Comment 5, emissions associated with malfunction events do not reflect source emissions under normal or usual operating conditions and thus do not reflect the source operations “under its physical and operational design.” Therefore, IDEM is not required to account for such events in a source’s PTE. This is as true for HAPs as it is for criteria pollutants. Although the Clean Air Act’s criteria and hazardous air pollutant programs may apply to different pollutants and may have different major source thresholds, the Clean Air Act consistently defines a major source in both programs in terms of both its actual and potential emissions. The definition of PTE in EPA’s HAPs regulations is the same as the definition in Part 51 applicable to state implementation plans. Compare 40 C.F.R. § 63.2 (PTE is defined as “the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. . . .”) to 40 C.F.R. § 51.166 (PTE is defined as “the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. . . .”).

Comment 31: IDEM’s analysis of HAPs emissions from the auxiliary boilers and gasifier preheater burners is based on steady state operations. However, HAPs emissions from combustion of natural gas, especially formaldehyde and aldehydes can be exponentially higher during startups, shutdowns and malfunctions. It is well known that, HAP emissions increase with reduced operating loads. Boilers are designed to run efficiently at full load where fuel combustion is nearly 100 percent efficient. At lower loads, and during startup, they are extremely inefficient, which results in incomplete combustion. This increases products of incomplete combustion, such as carbon monoxide (“CO”), aldehydes, and hydrocarbons. However, the relationship is not necessarily directly proportional and differs for individual HAPs as well as with the type of boiler.

Response 31: In calculating HAP emissions from boilers and the other IG combustion devices, it is standard practice to use the same emissions factors (lb/MMBtu), regardless of operating load of the combustion device. Further, the two emissions sources mentioned by the commenter, the auxiliary boilers and gasifier preheat burners, will not normally operate at very low loads. For example, the main need for both sources is during startups, at which time they will normally operate at greater than 50% load.

To support their contention that combustion devices have higher HAPs emissions at low loads, the commenter cites three references. The first two references (footnotes 11 and 12) address emissions from gas-fired turbines. The proposed IG facility does not have any combustion turbines and, from an emissions perspective, they are very different from boilers and heaters. The third footnote (13) references a study entitled “Gas-Fired Boiler and Turbine Air Toxics Summary Report”, August 1996. This report predominately discusses combustion turbines performance, which is not relevant to the IG combustion sources. This report also contains HAP testing results for two gas-fired utility boilers at various loads. However, that testing does not support the commenter’s contention that boilers at low loads have significantly higher HAPs. In contrast, the report states that emissions of the HAPs tested (formaldehyde, benzene, and toluene) “were not significantly impacted by unit load or excess air level and were lower than emissions from the combustion turbines” (pg. 30 and 67). Additionally, it is of interest that the emissions for the three HAPs that were detected in the boiler emissions were less than the sum of the emissions factors for these three HAPs in AP42 which was used by IDEM to calculate the IG gas combustion HAP emissions.

In conclusion, the use of applicable AP42 factors for natural gas and for estimating combustion HAP emissions for the IG facility was appropriate and is consistent with standard practice for the types of sources included in this proposed facility.

Comment 32: Considering these increased HAPs emission rates during SSM is enough to bring IG to over the 25 TPY major source threshold. Otherwise, the permit would need to include HAPs CEMs that record emissions at all times, including SSM.

Thus, because IG is a major source of HAPs, all of the NESHAPs that the TSD says are not applicable because IG is an area source are actually applicable.

Response 32: As explained in response to Sierra Club comment 28 above, HAP emissions associated with startup and shutdown have been evaluated and accounted for in determining the PTE of the facility. In regards to HAP emissions during malfunctions, see Response to Sierra Club Comment 30.

Synthetic Natural Gas Is Not Guaranteed to Have the Same Combustion Characteristics as Natural Gas

Comment 33: Synthetic Natural Gas Is Not Guaranteed to Have the Same Combustion Characteristics as Natural Gas

The Applicant derived emission factors for various HAPs based on U.S. EPA's *Compilation of Air Pollution Emission Factors* ("AP-42"), Chapters regarding natural gas combustion. Neither the Applicant nor IDEM provides a satisfactory explanation why emission factors derived for natural gas-fired combustion sources are considered applicable to combustion of SNG in IG.

Response 33: As explained in response to Sierra Club comment 29 above, the use of the AP-42 organic HAP factors for natural gas when determining the HAP emissions when burning SNG is conservative because natural gas contains more HAP emissions precursors than SNG. For mercury and lead, AP-42 was not used. Instead, the permit applicant developed specific factors based on the performance of controls inherent in the SNG production process.

Comment 34: First, while the produced SNG may have similar physical and chemical characteristics compared to pipeline natural gas, the two gases are just that: similar, but not identical. SNG may have a similar heat content, maximum sulfur fuel content, and higher methane content as natural gas but may have a different content of other components that affect the combustion process and the formation of pollutants.

Response 34: As discussed in response to Sierra Club comment 29 and 33, SNG is expected to have fewer organic HAPs and HAP formation precursors in it than natural gas. Therefore SNG is expected to have fewer HAP emissions, upon combustion, than natural gas. Regarding the non-organic HAP precursor trace constituents of coal (sulfur, chloride, fluoride, metals, etc.) from which the SNG is derived, these will removed by the intensive gas treatment and processing associated with the conversion of the solid feedstock into syngas and the syngas into SNG. These gas treatment and processing steps include water washing, acid gas removal, carbon adsorption and catalytic conversion.

All these processing steps, inherent in the SNG production process, are very effective in removing HAPs and HAP precursors. For example, these processing steps remove virtually all entrained particulate which would otherwise carry with it non-volatile metallic

HAP compounds. The water washing and wet scrubbings steps are very effective in removing sulfur, chlorine and fluoride compounds. Semi-volatile metallic compounds such as mercury are very effectively removed by sulfide carbon beds through which the syngas must pass. Additionally, of the very small amount of HAP compounds that pass thru these rigorous treatment steps, some amount of additional removal occurs from on the catalyst beds of the shift conversion and methanation processes. From an overall HAPs perspective, SNG combustion should have lower HAPs than natural gas combustion.

Specifically regarding metallic compounds (excluding lead and mercury which are calculated separately), IG’s estimated metallic HAP content of syngas is only slightly higher than the AP42 assumptions for natural gas for metallic HAPs. The gas treatment steps to convert the syngas to SNG are expected to remove approximately 85% of these metallic HAP compounds. Thus, the resulting SNG will have trace levels of metals that, cumulatively, are less than one quarter the AP42 metallic HAP factors for natural gas combustion. Therefore, even for metallic HAPs, the use of natural gas metallic HAP factors for SNG combustion is conservative.

Comment 35: Second, the Draft Permit does not contain a requirement that SNG be consistently produced to any particular specifications. For example, Draft Permit does not require testing for methane, hydrogen, carbon monoxide or moisture content or the higher heating value of the SNG, all of which affect the combustion process and the formation of combustion products including HAPs.

Response 35: The SNG is being produced and sold into the natural gas market. Therefore, it has to meet the same quality requirements that any natural gas producer must meet before placing gas in a pipeline. It will not be materially different than natural gas in regards to the constituents listed by the commenter and it is less likely to contain the organics that serve as the key combustion HAP precursors for natural gas.

Comment 36: **Non-Metallic HAP Emission Factors Used By Applicant Underestimate Potential to Emit.**

Even if one accepted the Applicant’s premise that SNG is equivalent to natural gas, the emission factors used by the Applicant to determine potential to emit for non-metallic HAPs (based on AP-42, Chapter 3.1) are not appropriate for estimating the “maximum capacity of a stationary source to emit any air pollutant” as required under 40 CFR §§ 63.2 and 63.41.

First, almost all of the tests evaluated for AP-42, were conducted for compliance purposes. Compliance tests, or source tests, are typically announced and, thus, give the operator the opportunity for optimizing equipment and operating at optimal conditions. As such, measured emission rates are most likely on the lower end of what would be observed under non-optimized conditions.

Second, the *average* emission factors from AP-42 are not appropriate to determine the *maximum* HAP emissions from the facility. Either the *maximum* or the 95th percentile emission factors measured during those tests would have been more appropriate. In a memorandum on HAP emission factors from natural gas-fired turbines, the U.S. EPA emphasizes that “[t]he 95th upper percentile emission factor may be more appropriate to use [than the average emission factor] for determining whether a source is major since it considers the test result variability.”

Third, most of the emission factors used have a rating of E. This is the lowest rating in terms of reliability.

The Environmental Appeals Board decision in *In re Peabody Western Coal Co.*, 12 E.A.D. 22, CAA Appeal No. 04-01 (Feb. 18, 2005) demonstrates why relying on emission factors is not sufficient in a potential to emit analysis. In that case, Peabody tried to establish that one of its facilities was a synthetic minor source for purposes of PSD. Peabody's request for a PTE limit of 185 ton/year relied on a quantitative estimate of the Facility's capacity to emit PM10. This estimate, in turn, relied on emission factors and assumed emission control efficiencies. Peabody estimated the uncontrolled emissions from each emissions unit based on the application of AP-42 emission factors. Peabody then estimated the net emissions from these units by applying assumed control efficiencies, and requested that Region IX establish a PTE limit for the Facility based on the cumulative total estimated net emissions. Similarly, Peabody's proposed compliance regimen did not include direct measurement of PM emissions.

U.S. EPA, Region IX, however, found a fundamental conceptual difference between PTE and actual emission performance that made Peabody's complete reliance on emission factors inappropriate in this instance. "While PTE is intended to identify the highest possible level of emissions that a facility is capable of releasing in light of its physical design and operational characteristics (considering enforceable restrictions on emission capacity), emission factors are intended to provide a generalized estimate of the average emissions performance of a particular type of emission source. According to AP-42, '[i]n most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).' As a result, according to Region IX, emission factors do not necessarily reflect the level of emission appropriate for calculating PTE." *In re Peabody Western Coal Co.*, 12 E.A.D. 22. Region IX stated that it "was not 'disputing Peabody's use of emission factors and control efficiencies for the purpose of calculating actual emissions,' but that because 'PTE is meant to be a worst case emissions calculation,' Peabody's approach was not adequate for 'the creation of a practically enforceable PTE limit for regulatory purposes.'" *Id*. The Environmental Appeals Board upheld the Region's decision that this could not be a synthetic minor source when its PTE were based on emission factors. *Id*. Similarly, IG's reliance of emission factors in its potential to emit HAPs analysis is inadequate.

Response 36: As an initial matter, the emission factors used for organic HAPs in natural gas are based on AP-42 Chapter 1.4, not Chapter 3.1 as suggested by Commenter. See Permit pdf pg 567 of 880.

The case cited by Commenter, In re Peabody Western Coal Co., 12 E.A.D. 22, is inapplicable to this situation. First, Peabody involved the use of AP-42 emission factors in establishing a PTE limit for the source. In contrast, IG is using AP-42 emission factors to calculate PTE of trace organic constituents found in natural gas for purposes of making an applicability determination and not for purposes of taking a PTE limit for these small HAPs. The Introduction to AP-42 contemplates the use of AP-42 emission factors for this purpose: "[e]mission factor use may also be appropriate in some permitting applications, such as in applicability determinations and establishing operating permit fees." Compilation of Air Pollutant Emission Factors, Fifth Edition, Introduction p. 2 (January 1995) (AP-42). AP-42 factors for natural gas are commonly used to estimate annual unlimited PTE for combustion sources.

Second, Peabody involved use of AP-42 emission factors to estimate and limit sourcewide fugitive particulate emissions (coal dust) from many coal handling points, which necessarily involves many different technical issues than the calculation of potential to emit trace HAP constituents in natural gas combustion exhaust.

In evaluating the technical issues involved in the calculation of PTE of HAPs for natural gas combustion sources, IDEM finds that the AP-42 HAPs emission factors used are representative of the natural gas combustion sources at the facility and appropriate for use in determining unlimited annual PTE of HAPs for these sources. Natural gas consists of a very high percentage of methane, typically over 85%, and smaller amounts of ethane, propane, and butane. AP-42 Chapter 1.4.1 (July 1998). There are also trace amounts of organic HAPs. See AP-42 Chapter 1.4, Table 1.4-3. Of the 24 organic HAPs compounds listed in the table on page 567 of the Permit, for 13 of these trace compounds, the underlying test data used to develop the respective emission factors in AP-42 are based on the method detection limits, meaning that the constituent was not detected at levels above the lowest level that could be detected by the test method.

Although several of the smaller trace HAP constituents are assigned an emission factor of "E," their use is appropriate in this case. As explained in the background document describing the development of the current emission factors found in Chapter 1.4, the underlying test data used to develop the HAPs emission factors were all assigned a data quality rating of "A." See Emission Factor Documentation for AP-42 Section 1.4 Natural Gas Combustion, Table 2.2-1 (March 1998). This means that the "tests are performed by a sound methodology and are reported in enough detail for adequate validation." Id. at Section 2.1. The "E" rating for these specific emission factors are because the emission factors are based on "less than three A- or B-rated source tests" (in this case, the source tests used were all rated "A"). Id. at p. 3.10.

Therefore, the points raised by Commenters overall about AP-42 are unpersuasive. It is noted that this project will have new, state of the art boilers, which should have combustion efficiencies better than the average performance of the units tested to establish the AP-42 factors. Therefore, use of these factors is conservative in that regard. Also, the Commenter's reference to a US EPA memorandum regarding gas combustion turbines to support a suggestion that the 95th percentile test result for estimating HAPs should be used is inappropriate because this project has no gas combustion turbines – the unique combustion characteristics of a combustion turbine are irrelevant to the types of gas-fired sources at this facility. Combustion HAPs emissions are very small, estimated to be under 1.6 tpy. Thus, even if the emission factor for any individual organic HAP is inaccurate by a significant amount, such error will not adversely impact the overall applicability determination.

Thus, use of AP-42 emission factors to estimate organic HAPs PTE for natural gas combustion sources at this facility is appropriate.

Comment 37: Hydrogen Chloride Emissions Were Omitted

During the gasification process, most of the chloride species in coal are converted to hydrogen chloride ("HCl"), which is a HAP. The actual concentration of HCl vapor in a coal gas stream will depend on the chlorine content of the coal, the gasification temperature, the type of gasifier, and the presence/concentration of alkali metals in the gasification system.

The PTE calculations do not provide estimates for HCl emissions from the flares, equipment leak fugitives, and sources that combust SNG, including the auxiliary boilers and preheaters, the AGR vent catalytic oxidizer. The permit record does not provide a satisfactory explanation why HCl emissions were not quantified for these sources.

The air permit application for the Kentucky NewGas SNG production facility, which was prepared by Trinity Consultants, established separate HCl emission factors for syngas and SNG combustion based on emission factors determined from a series of stack tests conducted at the Wabash River and Louisiana Gasification Technologies, Inc. ("LGTI") facilities. The Application and TSD provide no discussion whatsoever why these emission factors were not deemed equally applicable to combustion of SNG at the IG facility and instead zero emissions were assumed for combustion of these gases. Actual emissions of HCl from IG may be considerably higher than LGTI because of the substantially higher chlorine content in the Illinois basin coal that would be gasified at the IG facility compared to the western subbituminous coal from Rochelle mine in the Powder River Basin in Wyoming that was gasified at LGTI. The chlorine content of coal gasified at LGTI was measured at 0.0039 percent by weight (%wt). The Application, Permit Summary and Draft Permit are silent on the chlorine content of the coal the operator will gasify at the facility.

Response 37: No, HCl is generated during start up flaring of the syngas from gasifiers because the unit starts up on a feed, methanol, that does not contain any chlorine compounds. HCl is produced when coal is gasified. All but a trace amount of that HCl is removed in the quenching of the gas in the gasifier. Less than 10 ppm of HCl remains in the syngas. During a planned shutdown, a small amount of coal- or coke-derived syngas is vented to the flare. The HCl emissions at the flare during these conditions are no more than 0.0023 tons/year.

As the syngas is converted to SNG, this small amount of HCl is removed.

The commenter references other permit actions and the HCl emissions attributed to gasification products for other gasification plants. First, it should be noted that the permit record for this project has been supplemented with a quantification of the extremely small HCl emissions that may result from syngas combustion. Second, the gasification process in this case involves greater quenching and removal of HCl than would be found with different designs and this project involves extensive processing of the syngas to convert it to SNG while certain of the other projects involve the direct combustion of syngas. Lastly, there is no technical basis to assume that HCl would be present in the SNG even if other permitting actions have applied simplifying assumptions to this point. Also, we will note that the total HAPs attributed to syngas and SNG firing in this permitting action on a pounds/MMBtu basis are similar to or greater than the total HAPs presented in the references used by this commenter.

Comment 38: Other HAP Emissions Were Omitted

Similar to hydrogen chloride, the Applicant failed to account for emissions of a number of other HAPs including benzo(e)pyrene, carbon disulfide, dichloromethane (methylene chloride), hydrogen cyanide, perylene, and phenanthrene from sources that combust SNG. Again, the permit record provides no discussion why the emission factors developed for the Kentucky NewGas SNG production facility were not deemed equally applicable to combustion of SNG at the IG and instead zero emissions were assumed for combustion of these gases.

Response 38: The SNG is chemically derived from reactions of H_2, CO and water and those reactions do not produce the organic HAPs listed by the commenter. Kentucky NewGas in their assessment of SNG organic HAPs chose to use factors derived from the combustion of coal and from testing of a completely different type of gasifier than that to be used by IG. IG will use a GE quench gasifier which has significantly different operating parameters and produces significantly different syngas than the Conoco-Phillips gasifier whose test results which were used, in part, as the basis for Kentucky New Gas's HAPs factors. Ky NewGas's factors are not representative of the organic HAPs that are likely to occur when IG's SNG is combusted. The HAPs attributed to natural gas are more representative of those of SNG. It should be noted that with either approach the HAPs from SNG combustion are very small and the total using the factors for natural gas is actually greater than those attributed to SNG in the Kentucky New Gas documentation.

Comment 39: IG IS NOT A SYNTHETIC MINOR SOURCE OF HAPS AS THE DRAFT PERMIT FAILS TO INCLUDE ADEQUATE TERMS AND CONDITIONS TO CREATE FEDERALLY AND PRACTICALLY ENFORCEABLE LIMITATIONS ON IG'S POTENTIAL TO EMIT HAPS BELOW MAJOR SOURCE EMISSION THRESHOLDS.

As detailed above, IG is not a genuine minor source of HAPs as it will easily exceed the significance thresholds for a number of pollutants. As discussed above, a "synthetic minor" source of HAPs is one with potential emissions in excess of major source emission thresholds except that enforceable limitations (practically enforceable) on the source's potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. Therefore, IDEM could only find IG is a minor source if the permit establishes practically enforceable limitations that prevent it from exceeding those significance thresholds. The draft Permit does not meet that standard, so IG cannot deem this facility a synthetic minor source.

Response 39: See Response to Sierra Club Comment 27.

Comment 40: TESTING FOR THE RTO IS INADEQUATE
The draft permit only requires testing for methanol from the acid gas recovery unit's regenerative thermal oxidizer (RTO) once every five years. TSD at 40. A stack test once every five years does not adequately ensure that emissions of methanol are keep below the minor source threshold in the time period between the stack tests. Performance of the system can vary dramatically during five years. Also, the stack test does not provide any data on methanol emissions during startups, shutdowns and malfunctions as the stack test is performed only at steady state operations. Finally, the methanol testing of the RTO does not provide any information about other HAPs emissions from the RTO. Adequately testing would require a HAPs CEMS or at least quarterly stack testing, including testing during startup, shutdown and malfunction of all possible HAPs coupled with continuous parametric monitoring based on a well established correlation between the parameter monitored and the emission rates observed during the stack test.

Response 40: As indicated in the Response to EPA Comment 9, the requirements for testing and documentation of emissions for HAPs from the AGR units are being amended to include testing for additional HAPs other than methanol and the determination of emissions factors based on the units' emissions. Those factors will be applied to the flow from these units to determine total HAP emissions from the AGR units. Because the gases that are vented from the AGR to the RTOs are otherwise a process product stream, the composition of that stream and the emissions from the RTOs are not expected to vary. Further, proper operation of the RTO is assured through continuous monitoring of their operating temperature.

PERMIT CONDITIONS ARE NOT ENFORCEABLE

Comment 41: **HYDROCARBON FLARE**

The TSD claims that massive SO_2 emissions from the hydrocarbon flare will be avoided by only using methanol as a feed stock during startup. Condition D.2.4(3)A addresses this situation. However, Condition D.2.4(3) is too vague to be enforceable as a practical matter. The second paragraph of Condition D.2.4(3)A should have the following sentence added to the end of it to ensure its enforceability: **"The permittee may not introduce coal or pet coke into the gasifiers until the valve to the syngas hydrocarbon flare is completely closed."**

Response 41: The proposed permit includes requirements sufficient to ensure compliance with the startup SO_2 limit in Condition D.2.4(3)A. The permittee must use only methanol during startup conditions requiring flaring -- D.2.4(3)A. The permittee must continuously monitor and record flow rate to the flares –D.2.4(3)A. -- and record the date, time, and total number of minutes for each startup flaring event – D.2.9(d) -- as well as the feedstock used during each gasifier startup that requires flaring – D.2.9(e)i. These records must be used to determine and record emissions according to the calculations in the permit, including startup emissions – D.2.7(c) and D.2.9(f). Finally, for malfunction events that cause gases to be sent to a flare, the “root cause” analysis provision applies – this includes anytime gases are sent to the flare that are not startup or shutdown events – D.2.4(3)A. Therefore, specific monitoring and recordkeeping requirements already apply to each condition requiring flaring, whether the feedstock is methanol or coal or petcoke, and these conditions are practically enforceable.

Comment 42: Also, the TSD assumes maximum emission of 0.70 lb/hr SO_2 from the flare except during certain startup and shutdown events. Thus, the permit needs a condition limiting SO_2 emissions to 0.70 lb/hr except during startup and shutdown. This emission limit needs to apply at all time except startup or shutdown.

Response 42: The emissions estimate for the hydrocarbon flare of 0.70 lb/hr SO_2 set out in the TSD is for startup flaring. Compliance with this limit is achieved by the permit requirement to use only methanol during startup conditions requiring flaring -- D.2.4(3)A. Outside of startups and shutdowns, in normal operation the only emissions from the flare will be the combustion emissions from the pilot. The TSD sets forth an SO2 emissions estimate for the pilot of 0.00068 tons annually, based on 8,760 hours of operation, or less than 0.0002 lbs./hr. See TSD page PDF 491 of 880. These amounts, based on AP-42 emission factors for combustion of natural gas, are extremely small. There are no controls available for burners of this size and type, and no limitations are necessary or appropriate given the very small potential to emit of the units. However, for consistency, it is appropriate to include a requirement that the pilot operate on SNG or natural gas only, as is already included, for example, for the AGR RTOs (see Condition D.4.4).

The following changes have been made to the permit:

D.2.~~6~~**7** Flare Pilot Flame

In order to ensure compliance with Condition D.2.4, the flare must be operated with a flame present at all times when the Syngas Hydrocarbon Flare is in operation and at least one gasifier is in operation or in startup or shutdown. **Only natural gas or SNG shall be used in the pilot for the Syngas Hydrocarbon Flare (EU-001).**

D.3.6 Flare Pilot Flame

In order to ensure compliance with Condition D.3.4, the flare must be operated with a flame present at all times when the Acid Gas Flare, identified as EU-002 is in operation and at least one gasifier is in operation or in startup or shutdown. **Only natural gas or SNG shall be used in the pilot for the Acid gas Flare (EU-002).**

Comment 43: The draft permit uses emission factors to determine compliance with the SO_2 emission limits during startup and shutdown. See Draft permit at page 59. The draft permit has absolutely no compliance mechanism at all for SO_2 emissions from the hydrocarbon flare for times other than startup and shutdown. Id.

Response 43: As explained in response to EPA Comment 5, startups and shutdowns are the only operating scenarios in which flaring is expected at the syngas hydrocarbon flare in normal operation. Outside of startups or shutdowns, in normal operation the only emissions from the flare will be the combustion emissions from the pilot. To document the compliance status with the requirements of Condition D.2.4(3)(A), the permittee is required to maintain a record of the feedstock used during each gasifier startup requiring flaring, the routing of gas whenever a gasifier is depressurized during a planned gasifier shutdown, and the operating rate of each gasifier prior to and during a planned shutdown of a gas treatment train. *See* Condition D.2.9(e). Condition D.2.9(e) also requires that the permittee shall have available for inspection copies of the procedures used to implement the measures in the flare minimization plan (FMP) and records of training sessions on those procedures. Also, the Permittee shall have a written record of each root cause analysis, the actions recommended from the analysis, and documentation on the implementation of any corrective actions stemming from the root cause analyses under the FMP.

Comment 44: The draft permit must have monitoring for SO_2 emissions from the hydrocarbon flare that applies at all times, including startup, shutdown, malfunction and upset. IDEM must require a total sulfur monitor. See MONTANA SULPHUR & CHEMICAL COMPANY v. US EPA, ___ F.3d ____, NOS. 02-71657, 08-72642 (9TH CIR. JAN. 19, 2012) Slip Op. at 12; 73 Fed. Reg. at 21,426-21,428. In the alternative, IDEM could consider a grab or integrated sampling although at this point, it does not seem like that is necessary as total sulfur monitors have had adequate time to mature. *See e.g.* 73 Fed. Reg. at 21,429.

Response 44: The monitoring required by the permit is appropriate for this source. The case cited by the Commenter, *Montana Sulphur & Chem. Co. v. U.S. EPA*, 666 F.3d 1174 (9th Cir. 2012), arises out of SO_2 NAAQS attainment demonstrations in Montana and requirements (including flare emission limits) in the resulting SIP and FIP, and does not address or change the analysis of appropriate monitoring requirements for individual units at the IG facility. The Ninth Circuit did not find, as the commenter appears to suggest, that the types of monitoring discussed in the court's opinion must be applied to all flares in all circumstances. The Ninth Circuit decision is a narrow one – holding that EPA did not act in an arbitrary or capricious manner by requiring total sulfur monitoring and grab or integrated sampling in the FIP for Montana Sulphur Chemical Company's flares. This opinion does not stand for the proposition that IDEM "must require a total sulfur monitor."

In this case, monitoring for the hydrocarbon flare beyond what is required in the permit is unnecessary. (See, the responses to Sierra Club Comments 41, 42, and 43 for additional information on the compliance requirements for this unit.) The emissions factors specified for use in Condition D.2.7(c) are based on very conservative assumptions and the actual sulfur levels in the flared gases would be the same or lower than these numbers. In addition, the estimated PTE is very low, at only 1.97 tons per year (see TSD p. 9 of 43). As a consequence, any additional sampling, including continuous monitoring, is unnecessary and overly burdensome.

Startup SO_2 emissions will be negligible due to the startup feedstock required. The emission factor used to calculate SO_2 emissions during startup, 0.10 x 10-6 lb SO2/scf, is extremely low because it is based on flaring of syngas generated from methanol, which is virtually sulfur free. Permit Condition D.2.4.3 requires the use of methanol feedstock during startups. Thus, no sampling or other additional monitoring is necessary to determine compliance for startup emission limits.

For shutdown, even though the emission factor is based on very conservative assumptions, SO_2 emissions will be very low due to the strict requirements for shutdown operations. The emission factor used to calculate SO_2 emissions during shutdown is 0.001264 lb SO_2/scf. This sulfur content is calculated based on the conservative assumption that the feedstock contains highest sulfur content the plant is designed to handle (5.79%wt dry sulfur in coal/coke) and assuming all the feedstock sulfur is converted into sulfur compounds in the syngas and all sulfur compounds covert into SO_2 emissions when combusted in the flare. Actual sulfur content and SO_2 emissions per cubic foot of syngas flared should be no more than this conservative assumption, and will normally be lower. Therefore, any sampling or other additional monitoring would not provide additional meaningful information to assure compliance for shutdown emission limits.

Even with these conservative assumptions in the emission factor, SO_2 emissions from the hydrocarbon flare will be very low due to the strict requirements for shutdown in Condition D.2.4(3), including: 1) routing the contained volume of each gasifier train to a WSA during planned shutdown; and 2) gasifier feed rate reduction prior to a scheduled gas treatment train outage.

The emissions estimate for pilot fuel SO_2 emissions is based on the very low sulfur content of either pipeline quality natural gas or SNG which is used for the flare pilot in small quantities. For consistency with other terms, a requirement is being added to the permit that the pilot operate on SNG or natural gas only, as described in response to Sierra Club Comment 42.

Comment 45: RTO DOES NOT HAVE A MINIMUM TEMPERATURE
The Permit requires continuous monitoring of thermal oxidizer temperature and further requires that the unit be operated at or above a three-hour average temperature of 1,600°F, or some other value determined in a stack test. Draft Permit at pdf p. 80. There are two problems with this requirement.

First, the thermal oxidizer temperature determines the amount of emissions. Temperatures higher than design can significantly increase NOx while temperatures lower than design can significantly increase VOCs and aldehydes. Thus, we recommend that the Permit be revised to require testing to establish an operating range within which all limits are met and that this range be set as an enforceable permit condition.

Second, the permit does not consider a temperature below the three-hour average to be a deviation of the permit. *Id.* As explained above, thermal oxidizers should be operated in a fairly narrow optimal range. A lower operating temperature will increase emissions of VOCs and aldehydes. This problem could be solved by adopting our recommendation to establish an operating range.

Response 45: The primary purpose of the AGR thermal oxidizer is to provide thermal destruction of methanol and other organic and HAP compounds in the AGR vent stream. This is the classic use of this technology. To assure proper destruction, it is standard practice to require maintenance of a minimum operating temperature on the oxidizer. It is not customary for oxidizers to be required to undertake numerous stack test runs at multiple operating temperatures to try to establish a maximum temperature, or to discern an optimum. Rather, as is customary practice for thermal oxidizer controls, IG's thermal oxidizers will be required to conduct a performance test to demonstrate that the unit complies with the emission limits for methanol, other HAPs, and other emissions. Operators of thermal oxidizers have no incentive to operate significantly above their minimum required temperature, because doing so wastes fuel. A control system will ensure that the operating temperature is maintained.

The temperature monitoring requirements in Condition D.4.20 are included to ensure compliance with the corresponding emission limits. The stack test will determine the three-hour average temperature at which the unit is meeting the emission limits. Because some variability in operating temperature can be expected to occur, a set minimum temperature with no averaging would necessarily require operation of the unit consistently above that level, resulting in the wasted fuel addressed above. Therefore, IDEM determined that maintaining the units' three-hour average temperature at or above the three-hour average temperature achieved during the stack test is an appropriate means of assuring compliance with the underlying emission limit. The permit requires the temperature to be monitored continuously and response steps to be taken whenever the three-hour average temperature falls below that observed during the most recent compliant stack test.

Comment 47: The gasifier preheat burners do not have monitoring requirements:
There are five proposed natural gas-fired and SNG fuel-fired gasifier preheat burners, emission units EU-008A through EU-008E. Draft permit at pdf p. 94. These burners have very exacting emission limits. *Id.* at 94-95. The only compliance determination requirement for these limits is use of natural gas or SNG in the burners. *Id.* at 95. These are work practices, which EPA's NSR Manual ranks last in its compliance monitoring hierarchy. NSR Manual at H.5. IDEM should not rely on work practices alone unless no other preferred monitoring technique is feasible. If this is the case, IDEM should explain so.

Response 47: IDEM has already conducted a top-down BACT analysis for all the emissions in the gasifier preheat burners as included in Appendix B of the Technical Support Document. The control technologies evaluated for the gasifier preheat burners are as follows:

PM, PM_{10} and $PM_{2.5}$
(1) Mechanical Collectors (such as Cyclones or Multiclones);
(2) Wet Scrubbers;
(3) Electrostatic Precipitators (ESP); and
(4) Fabric Filter Dust Collectors (Baghouses).

Carbon Monoxide (CO)
(1) Regenerative thermal oxidation;
(2) Catalytic oxidation;
(3) Flares
(4) Combustion Control

Sulfur Dioxide (SO_2)
(1) Flue Gas Desulfurization
(2) Low sulfur fuel

Nitrogen Oxide (NOx)
(1) Selective Catalytic Reduction (SCR)
(2) Flue Gas Recirculation (FGR)
(3) Low NOx Burner (LNB)

The RACT, BACT, LAER Clearinghouse (RBLC) was reviewed to obtain recent determinations for these emissions from similar processes. The search criteria used was Gasifier Startup Burners/ Preheat Startup Burners for all the pollutants. There was no BACT determination for this category listed for the time period between 03/21/2000 and 12/30/2010, except Hyperion Energy that has a control device (Low NOx Burners) for the NOx emissions. The Low NOx Burners are not technically feasible for the preheat burners due to the design of the burners and the extremely high gasifier temperature required (2500 F). The burners are designed similar to a lance, or fuel nozzle, and are only used during preheat.

The burners fire into the gasifiers which do not include tubes or other heat absorbing material. This results in the temperature being much higher than many applications that incorporate low NOx burner technology. The extreme desired operating temperature is above the temperature that nitrogen breaks apart making NOx reduction not effective. The BACT concluded that there are no technically feasible add-on control technologies for these intermittently used, relatively small, clean fuel fired burners. Because the gasifier preheat burners will not have any control device, there are no monitoring conditions in the permit associated with emissions controls or their performance for this emission unit.

Comment 48: Emission Unit EU-012A does not have compliance demonstration testing requirements Feedstock that arrives by barge is unloaded to a hopper transfer point. This process produces fugitive particulate emissions that are identified as emission unit EU-012A. Draft Permit at 55. These emissions are controlled by work practices alone—wet suppression with a control efficiency of 90%. *Id.* at 56. This work practice is identified as Condition D.1.4(b) in the Draft Permit. *Id.* Compliance with Condition D.1.4(b) is supposed to be determined via Testing Requirement D.1.7(b). *Id.* at 59. This test—which monitors compliance with seven other conditions in addition to D.14(b)—calls for stack testing of a representative dust exhaust extraction system of baghouse. *Id.*

Emission unit EU-012A is not equipped with either a dust extraction system or a baghouse. It is controlled with wet suppression only. Furthermore, this emission unit is not included in the list of units to which testing Requirement D.1.7(b) applies. *Id.* This means that this testing requirement cannot be used to demonstrate compliance with Condition D.1.4(b). IDEM must alter testing requirement D.1.7(b) to clarify that this test cannot be performed on this unit, specify a new test of compliance, and require that test for emission unit EU-012A.

Response 48: IDEM has inadventently included emission unit EU-012A in Condition D.1.7(b), this is a typographical error that has been corrected . Sub-condition D.1.7(b) has been revised in the permit accordingly.

D.1.7 Testing Requirements [326 IAC 2-1.1-11]

....

(b) In order to demonstrate compliance with Condition**s** D.1.4(~~b~~**c**) - (h) and (k), not later than one hundred and eighty (180) days after initial startup of the first gasifier, the Permittee shall conduct stack testing of the emissions from a representative dust extraction system or baghouse or one of each if both are used controlling rail unloading to rail hoppers (EU-012G/H); Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F); Rail Hoppers Unloading to the Conveyor Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K); Stacker Belts to the Radial Stacker (EU-012L-M); Transfer Systems Consisting of Hoppers and Conveyor Belts Transferring Feedstock from the Piles to Classification Tower (EU-012R-S), Classification Towers (EU-012T-U), and Classification Tower to a Day Bin (EU-012V); Truck/Rail Conveyor Transfer Tower (EU-012Y); the truck stations unloading to a truck hopper (EU-012Z, AB and AC); and truck hopper unloading to the conveyor belts (EU-012AA); and one representative baghouse controlling the Radial Stackers to the Pile (EU-012N-O) to determine compliance with the PM, PM_{10}, and $PM_{2.5}$ emissions limitations, utilizing methods as approved by the commissioner. These tests shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

The emission unit, identified as EU-012A has compliance determination requirements in Condition D.1.6(c) - PM, PM_{10} and $PM_{2.5}$ Control and Condition D.1.12 - Record Keeping Requirements of the permit.

Comment 50: Emission Unit EU-012Z does not have emission limitations or monitoring Requirements

Emission unit EU-012Z is one of three truck stations that unloads to a truck hopper. Two of these units, EU-012AB and EU-012AC, are included in operating condition D.1.4, PSD BACT for particulate matter. Draft Permit at pdf p. 57. The third unit, EU-012Z, is not included in operating condition D.1.4. This means that the unit is not required to employ either a wet dust extraction system or a baghouse, and does not have enforceable maximum outlet concentrations for PM, PM_{10}, and $PM_{2.5}$. *Id.*
IDEM has not explained its reason for omitting EU-012Z from operating condition D.1.4. If the omission was intentional, IDEM must explain why this operating condition should not apply to this unit. If it was an oversight, it must be corrected.

Response 50: IDEM inadvertently omitted one of the truck stations unloading to a truck hopper, identified as EU-012Z and its conditions from the permit. There are three (3) truck stations unloading to a truck hoppers in the permit, identified as EU-012Z, EU-012AB and EU-012AC, these emission units are the same units with the same applicable requirements. This typographical error has been corrected by including the missing emission unit, EU-012Z back into the permit.

D.1.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Incoming Solid feedstock material handling and the Process area solid feedstock conveying storage, identified as EU-011A/B and EU-012A-AC shall be as follows:

....

(k) The PM, PM_{10} and $PM_{2.5}$ emissions from the Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012**Z,** AB, **- and** AC); and truck hopper unloading to the conveyor Belts (EU-012AA) operation shall be limited as follows:

....

Comment 51: COMPRESSOR FOR CO_2:
Presumably the CO_2 will be shipped out of the facility via a pipeline. The permit must contain an enforceable condition requiring this. If this is the case, the pipeline would need a compressor. The compressor engine must be included as one of the emissions units subject to BACT and inclusion in the ambient impacts analysis. If the compressor is going to be electric, than there must be an enforceable permit condition requiring that the compressor be electric.

Response 51: With respect to the assertion that a permit condition is necessary to require the shipment of CO_2 by pipeline, see Responses to Public Comments 7 and 10. The facility is designed to deliver at least 80% of the high-purity CO_2 manufactured by the AGR to a product pipeline. The Clean Air Act and the state air permitting rules do not provide IDEM with the authority to require the manufacturer of any product to ship it in a particular manner.

With respect to the pipeline compressor, it is not a point source of emissions and is therefore not included as a permitted emission unit. Fugitive emissions from the compressors are addressed in the permit. See Draft Permit Condition D.15.4. No permit condition requiring the use of an electric compressor is necessary—the permittee is not authorized to construct or operate a compressor that is a point source of combustion emissions.

Comment 52: EU-012R AND EU-012S:
The draft permit states that the two transfer systems identified as EU-012R and UE-012S are controlled with dust extraction systems <u>or</u> baghouses identified as C-012R and C-012S. Draft Permit at page 2 of 6. IDEM cannot permit hypothetical or alternative

sources. The draft permit must identify C-012R and C-012S as a specific device. It cannot be one of two possible devices. Similarly, Conditions (A)(2)(a) - (k) indentify “control devices” C-012B - M, T, U, V, Y, Z, AB, AC, AA . IDEM cannot permit generic “control devices.” Rather the permit must specifically identify the type of control devices.

Response 52: IDEM conducted a top - down BACT analysis for all these emission units comparing wet dust extraction systems and baghouses and in Step 3 of the analysis the percent reduction for both the wet dust extraction systems and the baghouses are the same.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Fabric Filter Dust Collectors (Baghouses) (>99% PM/PM10/PM2.5 Reduction);

(2) Wet Dust Extraction (>99% PM/PM10/PM2.5 Reduction).

The two systems offer comparable control of greater than 99% reduction of PM, PM10 and PM2.5 emissions. Because their percent control is the same and either would have to meet the same BACT emission limitation, the source can use one or the other to control the emissions of PM, PM10 and PM2.5, and IDEM has included in the permit compliance determination and monitoring requirements for both systems. In addition, IDEM believes that either of the control measures proposed by the source will be protective of human health and the environment.

Fugitive Emissions

Comment 53: The Haul Roads fugitive emissions calculation is inadequate

IDEM has failed to properly calculate fugitive particulate emissions from paved roads. This invalidates the PM10 and PM2.5 ambient impact analysis.

With some 32,659 vehicle miles traveled (VMT) annually on paved roads, IDEM calculates particulate emissions at only 0.4531 tpy. TSD at pdf p. 482. These emissions levels are far too small to be credible. The problem can be partially explained by the use of unrealistic or inaccurate variables discussed below.

Fugitive dust emissions from paved roads were calculated using AP-42 Chapter 13, Section 2.1: Miscellaneous Sources, Paved Roads. Performing this calculation using IG’s variables does yield the emissions they claim (assuming 90% control efficiency):

Table 1

	Max lb/hr	**lb/day**	**tpy**
PM10	0.0226	0.54	0.0906
PM2.5	0.0055	0.13	0.0222
PM	0.1124	2.70	0.4531

TSD at pdf p. 482. The problem lies in IDEM’s assignment of values to the variables in the equation. The calculation includes the following input variables:

1. Road Surface Silt Loading, sL
2. Average Truck Weight, W
3. Truck Trips per day
4. Total Round-Trip Distance
5. “Wet” days, P

Id. As will be shown below, the values for several of these variables are unrealistic or inaccurate.

Response 53: The values for input variables used in the roadway dust equation are reasonable as discussed in the following responses to Sierra Club Comments 54 through 68.

Comment 54: **The silt loading value is too small**

Dust emissions from paved roads vary with the amount of silt on the road surface, referred to as "silt loading." The TSD uses a background silt loading value of sL=1 g/m^2. There are several reasons why this value is inaccurate and understates the true silt loading value.

Response 54: Roadway silt loading is one of the parameters used in the AP-42 equation for paved roads. The higher the silt factor used, the higher the calculated emissions. IDEM used an assumed road silt loading factor of 1.0 g/m^2. The commenter suggests that this number is too low (and instead suggests in Sierra Club Comment 58 that it should be 9.7 g/m^2 (Steel/Iron Production mean silt from AP-42 table 13.2.1-3)). However, the value of 1.0 g/m^2 is reasonable for this particular facility for the following reasons:

- This silt factor is higher (i.e.: more conservative) than silt factors used for several other recent permitting actions for similar facilities.
- The IG facility is not similar to any of the industry types for which silt information is provided in AP42; for example IG is not an iron and steel production facility. Further, the industrial silt values in AP42 (for other types of industries) are from testing approximately 30 years ago, and are not necessarily relevant to modern facilities with extremely high levels of particulate controls (BACT) on all plant PM emission sources.

Each of the above points is discussed further below.

A review of the permitting record for other similar facilities shows their use of similar, but even lower silt loading factors for paved roadways.

- Duke Edwardsport IGCC project assumed 0.4 g/m^2 for their silt factor for paved roads;
- Cash Creek Generation SNG/NGCC permit in Kentucky used 0.4 g/m^2; and
- KY Newgas used 0.6 g/m^2 for their paved roadway calculations.

The use of 1.0 g/m^2 is higher than and more conservative than these other recent similar permits.

Regarding the appropriateness of silt factors presented in AP42, AP 42 lists default silt factors for public roads and typical silt loadings for certain types of industrial facilities. The default public road factors, depending on traffic usage range from 0.015 g/m^2 to 0.6 g/m^2. The proposed IG silt factor of 1.0 g/m^2 is higher (more conservative) than any of these numbers. While the roads within the facility will not be public roads, the silt loading is a function of nature of the road, its use, and its location – not who owns it (i.e.: public versus industrial).

AP-42 also lists what it calls "typical" silt contents for paved roads at several types of industrial facilities. However, that data is not particularly applicable to IG for several reasons.

- First, none of the industries listed are similar to the proposed IG facility.
- Additionally, even for those industries listed, a wide range of silt loadings are presented – without guidance on how to use that information.

- Also, those industrial facility silt loading values presented in AP42 Table 13.2.1-3 are based upon road dust samples collected in the mid to late 1970's through the mid to late 1980's. (http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s0201.pdf (page 16)) There is no information to know if the facilities tested employed any measures to minimize fugitive dust of material handling or other dust sources nearby. It is likely that a well-managed modern facility with high degree of control of nearby fugitive dust sources would have significantly lower roadway silt levels than AP42's thirty year old industrial roadway data.

For additional perspective on silt values, there is the background documentation used by EPA to support the development of Section 13.2.1 of AP-42 and, in particular, the data included in Table A1-2 and Table A1-4 of the September 1997 Addendum to Emissions Factor Documentation for AP-42 for Paved Roads which is one part of the collection of background documents for this AP-42 section.

These tables show actual silt loading values from tests on a number of industrial paved roads and help illustrate the wide range of results summarized in AP-42 for industrial facilities. Review of the data in the background document shows that a significant portion of the industrial roads in the studies had silt loading values equal to or less than 0.4 g/m2. (http://epa-sdcc.ornl.gov/pdfs/b13s02-11.pdf) The use of 1.0 g/m2 as the silt loading factor in estimating fugitive $PM_{10}/PM_{2.5}$ emissions was within the range of silt loadings found at industrial facilities.

Given that IG will be a new facility with BACT level control on all particulate sources, roadway silt deposits from nearby operations should be low and it is reasonable to assume that silt levels will be consistent with tests from the better/lower end of the range of the industrial data available.

Comment 55: **Default baseline values are inadequate**
AP-42 specifically states that the use of a tabulated default value for silt loading results in only an order-of-magnitude estimate of the emission factor for fugitive dust from truck traffic on paved roads, and, therefore, the collection and use of site-specific silt loading data is "highly recommended." AP-42, 13.2.1-8. This is even truer for industrial sites, given that "the collection of site specific silt loading data from industrial roads is easier and safer than for public roads." *Id.* at 13.2.1-9. Therefore, to be enforceable, the permit must require at least daily monitoring and reporting to confirm that the silt load upon which any final permit is based is complied with in reality.

Response 55: The silt factor assumed in the estimation of fugitive dust from paved roadways is considered reasonable and conservative as discussed in response to Sierra Club Comment 54. It is not common to require testing of every parameter used in every emissions estimate. Specific to roadway silt, it is not common in permits for industrial facilities to require such testing. For example, no such testing has been required of the three gasification plants listed in response to Sierra Club Comment 54 which assumed an even lower silt loading than IG. The silt factor used in estimating this small emission source at the IG facility has a reasonable and conservative basis and does not require testing.

Comment 56: In the event that a site-specific value is not available, AP-42 recommends the selection of an appropriate mean value from a table listing silt loadings that were experimentally determined for a variety of industrial roads but cautions that the quality rating of the equation decreases by 2 levels. The industrial roadway table provides a range of mean silt loading values from 7.4 to 292 g/m^2. AP-42 Sec. 13.2.1-4, Table 13.2.1-4.

Response 56: AP42 does not “recommend” the selection of a mean value from the table of industrial silt loadings. It merely states that an appropriate value “may” be selected from those tables. However, as discussed in response to Sierra Club Comment 54, there are no appropriate values listed in AP42 for this specific type of facility. Instead, an appropriate value was selected based on review of other permits and the background test data used in developing AP42 as discussed in response to Sierra Club Comment 54.

Comment 57: **The chosen silt loading value is inadequate for industrial roads**
The paved roads of interest here are within the boundary of an existing industrial site and thus are industrial roadways. Silt loading values of industrial roads are much higher, vary greatly, and are reported in chapter 13 of AP-42. AP-42, 13.2.1-10, Table 13.2.1-3.

Response 57: See response to Sierra Club Comment 54.

Comment 58: IDEM used a silt loading value of 1 g/m^2, thereby considerably underestimating PM emissions from paved roads within the facility. TSD at pdf p. 482. A more appropriate silt loading value is 9.7 g/m^2, the mean silt loading of an iron and steel production facility. AP-42, 13.2.1-10, Table 13.2.1-3. This value is appropriate not only because it is near the lower end of the AP-42 industrial roadway range, but also because these facilities use coal. If this value is used in the calculation, the PM emissions from paved roads increases to 7.165 tpy of PM_{10} and 1.759 tpy of $PM_{2.5}$, an increase of more than an order of magnitude. If the upper end of the industrial road range of 292 g/m^2 is used, which is appropriate for a potential to emit calculation, the emissions increase hugely to 159 tpy of PM_{10} and 39 tpy of $PM_{2.5}$.

Response 58: AP42 lists ranges silt loadings for a variety of industrial categories, including data for an iron and steel facility. However, as discussed in response to Sierra Club Comment 54, IG will not be an Iron and Steel facility and mean silt values for that industry type are not appropriate for characterizing IG’s emissions. Instead, an appropriate value was selected based on review of other permits and the background test data used in developing AP42 as discussed in response to Sierra Club Comment 54.

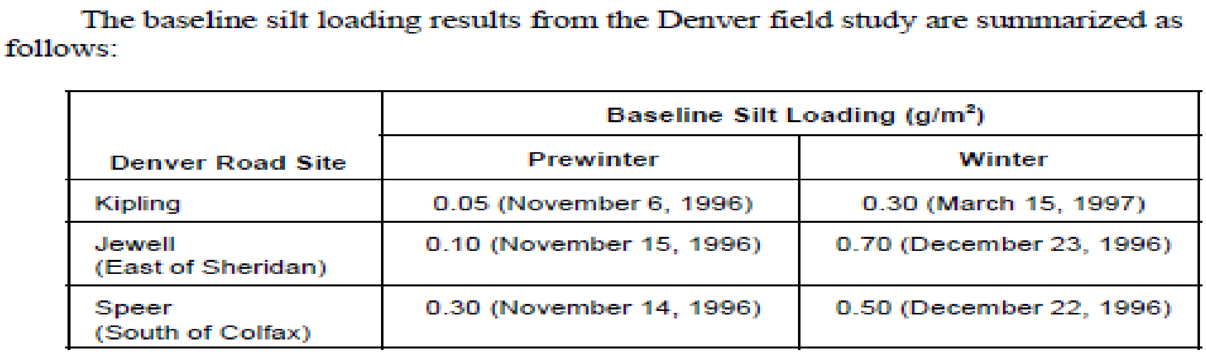
Comment 59: In no event is there any justification for the use of IDEM’s 1 g/m^2, which is well below the bottom of the range given in AP-42. IDEM offers no data to support its 1 g/m^2value. The TSD does say this is reasonably considering the control achieved through road watering. However, setting a low silt content based on control achieved through road watering is double counting because road watering is already considered in the TSD values by including a 90% control factor. In order words, IDEM seems to set a low silt loading value based on road watering and then also set a high control factor based on road watering. There is actually no justification for either.

Response 59: A detailed explanation of the basis for the selection of 1 g/m2 silt loading factor is provided in response to Sierra Club Comment 54. Also, the commenter mischaracterizes statements on the emissions calculation table which mention that the silt factor is conservative. The factor was not double counting road watering control. The factor, as discussed in response to Comment 54, instead does consider the fact that other nearby dust sources will have planned frequent wet suppression to achieve BACT on those sources. The wet suppression and other BACT controls on material handling steps will reduce the overall ambient dust levels and reduce the dust/silt that could become deposited on the roadways.

Comment 60: **The effect of wintertime on silt loading is ignored**
In the winter, roads covered with ice and snow are treated with application of antiskid abrasives. For areas that experience frozen precipitation and application of antiskid material, AP-42 recommends a winter baseline multiplier. AP-42, 13.2.1-8. For low volume roads (those with Average Daily Traffic of less than 500) the multiplier is four,

meaning that the silt loading value should be quadrupled in the winter months. AP-42 also suggests that each application of antiskid abrasives leads to “an additional (but temporary) silt loading contribution of 2 g/m^2.” *Id.*

Response 60: AP42 does mention that higher silt loadings can occur “in areas that experience frozen precipitation with periodic application of antiskid material”. However, AP42’s reference to adjustments for these factors is an analysis done using studies in Denver Colorado and Duluth Minnesota associated with the application of sand as a wintertime antiskid material. (http://www.epa.gov/ttnchie1/conference/ei11/dust/cowherd.pdf). In southern Indiana, which has much milder winters than Colorado or Minnesota, salt is the common wintertime road treatment. AP42, (page 13.2.1-8) specifically states that “Ordinary rock salt and other chemical deicers add little to the silt loading, because most of the chemical dissolves during the snow/ice melting process.” Nevertheless, even with sand, the increase to baseline silt content is not necessarily significant compared to IG’s assumed silt level. Below is the Denver silt loading study from the above referenced EPA report. Note that even winter silt loadings on the tested roads, treated with sand for antiskid in winter, are below the assumed 1.0 g/m2.



The baseline silt loading results from the Denver field study are summarized as follows:

Denver Road Site	Baseline Silt Loading (g/m^2)	
	Prewinter	Winter
Kipling	0.05 (November 6, 1996)	0.30 (March 15, 1997)
Jewell (East of Sheridan)	0.10 (November 15, 1996)	0.70 (December 23, 1996)
Speer (South of Colfax)	0.30 (November 14, 1996)	0.50 (December 22, 1996)

Comment 61: IDEM has failed to even consider whether a wintertime baseline multiplier or an additional antiskid contribution is appropriate. This is particularly troubling in light of IDEM’s allowance of 117 “wet” days throughout the year—some of these days must include snow and ice. IDEM must either adjust its wintertime silt loading calculations or explain why it has disregarded AP-42’s recommendation that it do so.

Response 61: See response to Sierra Club Comment 60.

Comment 62: **Mud and dirt trackout is ignored**
Similarly, IDEM has not considered the silt loading contribution from mud and dirt trackout. AP-42, 13.2.1-8. There are at least some unpaved areas on IG’s cite—there are two bulldozers making more than 500 trips a day on unpaved roads. Application at pdf p. 227-30. These bulldozers are used to maintain the feedstock pile and help feed the hoppers. Application at pdf p. 11, 15. If these bulldozers ever leave the unpaved area, or if any other vehicles ever drive into the unpaved area, a track out point is created.

Response 62: The commenter has suggested that since there are unpaved areas at the IG facility, and since vehicles may occasionally travel on those unpaved areas and return to the paved roads, that this constitutes a trackout point that should be accounted for in the roadway emissions calculations.

AP42 does suggest an adjustment to the PM emissions calculations from public paved roadways for mud/dirt trackout from “active construction sites” due to the significant mud and dirt that can be carried onto public roads by construction traffic. This suggestion is for use by states/counties in estimated and modeling regional emissions for regulatory purposes. AP42 also suggests evaluating other types of trackout to public roads (i.e. dirt roads in agricultural areas joining public paved roads.) However, AP42 is not specific about how to address the less significant trackout from sources other than active construction sites. Also, AP42 makes no mention of trackout in the context of industrial facilities emissions calculations.

Specific to the IG facility – the plant will not contain an active construction site once it begins operation. When the plant is in operation, the proposed permit requires that all haul roads be paved, and the permit requires prompt cleanup of any spilled material. The paving of all haul roads will eliminate dirt trackout effects from haul vehicles. Also, the requirement to promptly cleanup spilled material (permit condition D.12.4.3) would logical extend to significant deposits of any type on the road including occasional trackout from non-routine activities. For these reasons, trackout impacts are expected to be minimal and to be reasonably accounted for in the silt factor of 1.0 g/m3 which, as discussed previously (response to Comment 54), is an appropriate and conservative value for this type of facility.

Comment 63: It may be that Indiana Gasification intends to keep its bulldozers in unpaved areas and its trucks on paved roads at all times. If this is IG’s intent, these limits on vehicular traffic must become enforceable permit conditions. If IG does intend to allow vehicles to travel on both paved and unpaved roads—which seems much more likely—then mud and dirt trackout must be factored into the haul roads fugitive emissions calculations. IDEM did not do this, and rather than making improbable assumptions about intended vehicle traffic, we conclude that IDEM simply ignored the silt loading contribution from mud and dirt trackout.

Response 63: There is no routine reason for the bull dozers used to manage the stockpiles to travel or cause “track-out” on paved roadways. Also, as explained in response to Sierra Club Comments 54 and 62, the conservative silt factor and existing permit language adequately address this issue.

Comment 64: **The vehicle miles traveled calculation is unsupported and likely too small**
IDEM has also not accounted for all of its truck traffic. In addition to coal and coke feedstock, the plant will use aqueous ammonia in its SCRs, diesel and gasoline to power its generators and vehicles, and glycol for use in its absorbers. The plant will be selling sulfuric acid and argon. Draft Permit at pdf p. 1. All of these incoming and outgoing materials must be moved somehow, but the permit makes no consideration for any of them in its calculation of vehicle miles traveled. IDEM has only the most general description of truck traffic. Draft Permit at pdf p. 156. There is no comprehensive explanation of how many trucks there will be, what they weigh, what they are used for, and how often they will be used. Without such an explanation, the haul roads particulate emissions calculation is inadequate.

Response 64: The emissions calculations for haul vehicles on paved roadways are presented in the TSD on pages 576 and 577 of the pdf and show the number of truck trips, assumed weight of the trucks and vehicle miles traveled. These calculations represent three categories of trucking activities: 1) 187.6 trucks/day for truck receipts of coal or coke feedstocks; 2) 51.7 trucks/day for truck hauling of byproduct slag; and 3) 31 trucks/day for other miscellaneous trucking, as a conservative contingency to cover other trucking activities mentioned by the commenter. The estimate for miscellaneous trucking addresses trucking of other materials such as sulfuric acid, diesel, gasoline, ammonia, argon, methanol, slag filter cake, cooling tower chemicals, glycol, and trash.

The last of these categories was included to address other miscellaneous trucking activities mentioned by the commenter. This 31 truck/day contingency category is presented together with, and as part of, the Slag Trucking emissions calculation TSD page 577. This conservative contingency, together with conservative estimates for coal/coke trucking and slag handling are more than adequate to address all the facilities trucking activities.

The permit assumptions are overall very conservative. For many days, actual truck vehicle miles traveled will be significantly less than the daily maximum estimated. For example, the facility will, at times, receive feedstock coal or coke by either rail or barge instead of by truck. Likewise, the permit assumptions for trucking of slag included double handling all the facility slag production by transporting it to a temporary storage pile. In practice, most of the time slag is expected to be hauled directly offsite to customers (which shortens the on-site trucking distance and avoids double handling/double trucks.) Also, product sulfuric acid and argon are expected to be shipped primarily by rail.

Comment 65: The draft permit does not have enforceable conditions which lead to 90% control efficiency

The TSD emission calculations of fugitive PM, PM_{10} and $PM_{2.5}$ assume 90% of these emissions. However, the draft permit does not contain any enforceable emission limits to ensure that 90% controls are achieved, much less continuously achieved. IDEM has declined to use any formal controls at all to reduce particulate emissions from haul roads. In its application, IG gave this description of its controls:

These emissions are very small, even uncontrolled result in only 0.53 tons/yr. Because of the very small amount of emission, no formal controls are proposed beyond just good housekeeping, i.e.: cleaning off the roadways of any material spilled or other road cleaning if visible emissions are observed.

BACT for PM_{10} is proposed to be good housekeeping of roadways by cleaning roads if visible emissions are observed or if material is spilled onto roadways.
Application p. 5-36 pdf 82. As explained above, emissions from haul roads are “very small” because they have not been properly calculated.

Response 65: The originally submitted permit application was amended to increase the amount of truck traffic and the BACT analysis was amended to require the use of wet suppression to achieve 90%. Permit conditions requiring controls on haul roads are in D.12.4, D12.5 and D.12.6. For additional information about proposed improvements to these permit conditions see response to Sierra Club Comment 67.

Comment 66: IDEM assumes these “good housekeeping” practices will achieve a 90% control factor—“the highest specified in the [RACT/BACT/LAER Clearinghouse] for such sources.” TSD at pdf p. 774.

Response 66: See response to Sierra Club comment 67.

Comment 67: IDEM has not adequately explained how it arrived at a control factor of 90%. Wet suppression is the only control to be used on the paved roads, and it is subject to the following exceptions:

- Rainfall of 0.1 or more inches has accumulated during the 24-hour period prior to the scheduled treatment,
- It is raining or snowing at the time of the scheduled treatment,

- The ambient air temperature is at or below 32 degrees, or forecast to be so within the next 24 hours,
- A significant portion of the haul road is covered by ice or snow or a majority of the road remains wet from recent precipitation or the previous watering, or
- The road is not being used as a haul road on that day.

Draft Permit at pdf p. 109. The 30-year mean temperature in southwest Indiana in January is 34°F. Indiana State Climate Office, (*available at* http://climate.agry.purdue.edu/climate/index.asp). This means it will be below freezing nearly half the time. IDEM also assumes 9-10 days of precipitation each month. Indiana Gasification could go days or even weeks without any wet suppression at all, and yet IDEM has assumed it 90% control efficiency even for those periods of time when the permit does not require wet suppression.

Response 67: Even uncontrolled paved roadway dust emissions are very small. Uncontrolled, the emissions from paved haul roads are conservatively estimated to be no more than 1.3 tons/yr PM_{10}, and 0.3 tons/yr $PM_{2.5}$ before control. With controls, emissions are 0.13 tons/yr PM_{10} and 0.03 tons/yr $PM_{2.5}$. The permit requirement regarding the use of wet suppression to achieve 90% control effectiveness was based on the BACT review of other recently permitted facilities, including ones with the use of wet suppression with a control efficiency of 90%. (e.g. 2008 Ohio River Clean Fuels RBLC OH-0317, 2010 Cash Creek Gasification KY permit V-09-006). In addition to the use of wet suppression, roadway dust will be controlled by good housekeeping (prompt cleanup of spills), and speed limits. Upon further review, several revisions to the permit conditions are appropriate to add clarity and reduce the amount of time when the allowable exceptions to the use of wet suppression would be in effect, and either vacuum sweeping or wet suppression will be required when the ambient air temperature is below 32°F.

In the originally proposed permit, wet suppression treatments would not have been required if there had been a threshold amount of rain in the past 24 hours. This permit condition has been amended to excuse treatments only if the roadway remains wet from a previous precipitation or treatment. This avoids the need to quantitatively monitor precipitation, while still recognizing the control benefits of natural wet suppression.

Also, in the originally proposed permit conditions, wet suppression would not have been required when ambient temperatures were forecast to be below 32°F in the next 24 hours. Although this recognized the safety sensitivities of wetting a road in possible freezing conditions and the fact that fugitive dust is much less mobile in freezing conditions, this exemption is being modified to exempt wet suppression only when the actual ambient air temperature at the time of the scheduled wet suppression is below 32°F, and to require vacuum sweeping in lieu of wet suppression if the Permittee takes advantage of the temperature exemption. Paved haul road wet suppression when the actual temperature is below 32°F is not deemed appropriate or necessary for the following reasons.

- There are practical and safety limitations of using wet suppression on paved roadways in freezing temperatures.
- In freezing conditions, there is a natural mitigating effect on the mobility of surface fugitive dust from project and regional sources. For example, a review of ambient particulate monitoring data shows a significant drop in peak ambient particulate levels in freezing conditions. Dust is generally not as much of a concern in freezing conditions.
- A new permit condition requiring vacuum sweeping when wet suppression is not employed due solely to freezing temperatures.
- A new permit condition limiting vehicle speeds will afford some additional control, including those times when no wet suppression is used.

- A review of past temperature data for the area (Evansville Met data for 2006-2009) shows that temperatures consistently below 32 F are infrequent in this area. In fact, less than 1% of the time the temperature gets that low without either precipitation (which would provide natural mitigation) or warmer temperatures within the past 48 hours (which would allow the use of wet suppression). Accordingly, the exemption from watering at temperatures below 32 degrees F would not result in significant periods of no wet suppression.
- Although a portion of the benefit of wet suppression is the wetting of surface dust particles to limit their mobility, an additional benefit is that some roadway dust is washed off the roadway. This benefit, from an active and ongoing wet suppression program, would continue even during brief interruptions due to cold temperatures.

Additionally, in considering the appropriateness of allowing infrequent exceptions to some roadway dust control measures, it is noteworthy that the ambient air quality standards for particulate are probabilistic standards, which means that a few values above the standard would not constitute an exceedance of the standard. The very conservative assumptions in the permit review provide adequate assurance that the project will not cause or contribute to a violation of the NAAQS. For example:

- The project air quality analysis assumed that the worse-case paved haul road emissions occur on a day when all other project sources are at their worst case emissions rates, and the background ambient levels are at their worst case levels, and wind conditions are present which result in the worst case dispersion characteristics. This is an extremely unlikely and conservative scenario given the actual variability of haul road traffic, wind speed and direction, and background ambient concentrations.
- As discussed in response to Sierra Club comment 64, the total truck traffic and vehicle miles travelled assumed in the permit evaluation is very conservative. Actual truck traffic on many days will be much less than the level assumed in the permitting. Even no roadway controls at such times would result in no more emissions than were assumed in the permitting.
- Also, as mentioned above, even in the brief absence of wet suppression treatment, some dust control is achieved by good housekeeping, speed limits, continuing benefits from past wet suppression, and natural mitigation from the sub-freezing temperatures.

Therefore, the Section D.12 has been revised in the permit accordingly.

D.12.5 Compliance Determination Requirements

To demonstrate compliance status with Condition D.12.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT:

(a) Wet Suppression **for roadway dust control** shall be performed on paved Haul Roads, except when:

~~- Rainfall of 0.1 or more inches has accumulated during the 24-hour period prior to the scheduled treatment,~~
- It is raining or snowing at the time of the scheduled treatment,
~~- The ambient air temperature is at or below 32 degrees, or forecast to be so within the next 24 hours,~~
- **The subject** ~~A significant~~ portion of the haul road is covered by ice or snow or ~~a majority of the road~~ remains wet from recent precipitation or the previous **wet suppression** ~~watering~~, or
- The road is not being used as a haul road on that day.

If the ambient air temperature is below 32°F at the time of a scheduled wet suppression

treatment, the permittee may clean the roadway dust with a vacuum sweeper in lieu of the wet suppression treatment.

(b) Compliance shall be demonstrated **for each active haul road** using records of haul road usage and control measures ~~and~~**. The frequency of required roadway dust control treatments for haul roads with between one (1) and ten (10) truck trips per day shall be at least every other day, unless a treatment is not required for one of the reasons under (a) above. For haul roads with more than 10 trucks per day, the frequency shall be sufficient to achieve 90% control based on** the following formula or an equivalent:

Control Efficiency = 96 – (0.263 * (T/C))

Where:
Control Efficiency = percent control efficiency
T = Daily truck trips on roadway (truck trips/calendar day)
C = Number of ~~Wet Suppression~~**roadway dust control** treatments per **calendar** day ~~(watering events / calendar day)~~

For the purposes of this formula, if at the time of a scheduled roadway dust control treatment, the treatment is not required for one of the reasons under (a) above, such an event shall be counted as a roadway dust control treatment.

(c) Haul truck speed limits on haul roads shall be posted as 15 miles per hour or less.

Compliance Monitoring Requirements

D.12.6 Ambient Temperature Monitoring

To demonstrate the compliance status with Condition D.12.5, the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32^{o}F.

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

D.12.~~6~~**7** Record Keeping Requirements

To document the compliance status with Condition**s** D.12.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and Condition D.12.5 – Compliance Determination Requirements, the Permittee shall maintain the following daily records for haul roads:

(1) The number of trucks on the haul road each calendar day.

(2) The date, approximate time, and type of each roadway dust control treatment.

(3) If a treatment is **not required and not performed pursuant to D.12.5(a)** ~~skipped~~, records shall be maintained **documenting** ~~of~~ the reason (i.e.: the ambient temperature, **precipitation,** ~~recent rainfall~~, ~~road conditions observation,(snow~~ **already wet roads**, haul road not used, etc.).

Comment 68: Even IDEM's own formula for calculating control efficiency demonstrates that this figure is unrealistic. The formula is:

Control Efficiency = 96 – (0.263*(T/C)
Where: T = daily truck trips;
C = Number of wet suppression treatments per day.

Draft permit at pdf p.110. This formula shows that, with IG's average of 186.8 truck trips per day, there will be **eight** applications of wet suppressant needed each day to maintain 90% control efficiency:

Control Efficiency = 96 – (0.263*(186.8/**8**)
= 89.9%

IDEM cannot reasonably expect to achieve 90% control efficiency if it excuses wet suppression so frequently. There is also no explanation of how Indiana Gasification will determine if a tenth of an inch of rain has accumulated in the last 24 hours, what constitutes a "significant portion" of ice or snow coverage, what constitutes the road "remain[ing] wet," or how IG will determine and enforce which days the road will not be used. IDEM cannot simply rely on vague assurances and assume 90% control efficiency despite mathematical evidence that it cannot be achieved.

Response 68: As discussed in response to Sierra Club comment 67, the permit language is being changed to allow fewer exceptions from the requirement for controls and remove the need for certain potentially subjective terminology.

Comment 69: **Bulldozer controls are overestimated and unenforceable**
IDEM also assumed 90% control efficiency for its bulldozer activity. Draft Permit at pdf p. 465. IDEM cannot assume 90% control efficiency without an enforceable permit limit to that effect. IDEMs permit limits for the bulldozers are just as inadequate as those for the haul roads. Draft permit at pdf p. 58.

Response 69: The coal/coke pile dozer permit conditions D.1.4.(i) and (j), D.1.6 (d), and D.1.12(e) require the use of wet suppression. Similarly, permit conditions D.13.4, D.13.5 and D13.6 require wet suppression control of the slag pile dozer activities. The assumption of 90% control efficiency is reasonable for regular wet suppression of such activities. Aggregate piles will retain moisture longer than, for example, paved roadways, allowing less frequent watering to achieve the same level of control

The Permittee has agreed to certain revisions related to the conditions D.1.6(d) and D.13.5. Below is revised language for those and related conditions. This language narrows the provision that allows the permittee to delay wet suppression if is raining or snowing or if temperatures are below freezing, which provision is appropriate for the following reasons.

- If it is raining or snowing, natural wet dust suppression is achieved.
- If temperatures are below freezing, it is not reasonable to require water sprays onto coal/coke storage piles. Also, at freezing conditions, the moisture present in the coal/coke (naturally present and from previous wet suppression) will help hold available dust particles together, significantly decreasing their likelihood to become airborne.
- The emissions mitigation effect of freezing weather is more significant for the coal/coke/slag piles than it would be for a paved roadway because aggregate piles will retain moisture much longer, allowing less frequent watering to achieve the same level of control and allowing enhanced mitigation benefits in freezing temperatures. This is one reason for differences in the permit conditions for dozer activities on piles versus those for truck traffic on paved haul roads.

Therefore, the Sections D.1 and D.13 have been revised in the permit accordingly.

D.1.6 PM, PM_{10} and $PM_{2.5}$ Control [326 IAC 2-7-6(6)]

……

(d) In order to ensure compliance with Condition**s** D.1.4(i) and (j), wet suppression using water sprays shall be used daily on active areas of the pile (areas with dozer activity and /or new feedstock being loaded). The non-active areas of the pile will have wet suppression applications weekly.

Wet suppression treatments of feedstock piles may be delayed ~~for 24 hours~~ **until the next day** when**ever**:

- ~~Rainfall of 0.1 or more inches has accumulated during the 24-hour period prior to the scheduled treatment,~~
- It is raining or snowing at the time of the scheduled treatment, **or**
- The ambient air temperature is at or below 32°**F** ~~degrees~~, ~~or forecast to be so within the next 24 hours,~~
- **The subject** ~~Dozer activity~~ area~~s~~ ~~are~~ **is** covered by ice or snow or standing water, ~~or~~
- ~~The dozers are not being used on that day.~~

……

D.1.12 Ambient Temperature Monitoring

To demonstrate the compliance status with Conditions D.1.6(c) and (d), the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32°F.

D.1.12~~2~~**3** Record Keeping Requirements

……

(d) To document the compliance status with Condition**s** D.1.4(b) - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.1.6(c) - PM, PM_{10} and $PM_{2.5}$ Control, the permittee shall maintain the following daily records:
- The date of each unloading operation.
- A log indicating whether or not water sprays were used and whether or not the level in the hopper ever exceeded the height of the sides of the barge unloading hopper during each unloading.

If a treatment is **not required and not performed pursuant to D.1.6(c)** ~~skipped~~, records shall be maintained **documenting** ~~of~~ the reason (i.e.: the ambient temperature **or** ~~,~~ **precipitation** ~~rainfall, etc~~.).

(e) To document the compliance status with Condition**s** D.1.4(i), and (j) - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.1.6(d) - PM, PM_{10} and $PM_{2.5}$ Control, the Permittee shall maintain the following daily records :

- The date and approximate time of each feedstock pile watering treatment.

- If a treatment is **not required and not performed pursuant to D.1.6(d)** ~~skipped~~, records shall be maintained **documenting** ~~of~~ the reason (i.e.: the ambient temperature, **precipitation, or the subject area is covered by ice or snow or standing water.**~~recent rainfall, snow, etc.~~

……

D.13.5 Compliance Determination Requirements

To demonstrate compliance status with Condition D.13.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, wet suppression shall be applied weekly to the entire slag storage pile/pad. Dust control is aided by the fact that the incoming slag is inherently wet. Additional wet suppression should be applied if any visible emissions are observed.

Wet suppression treatments of the slag pile area may be delayed ~~24 hours~~ **until the next day** when**ever**:

- ~~Rainfall of 0.1 or more inches has accumulated during the 24-hour period prior to the scheduled treatment,~~
- It is raining or snowing at the time of the scheduled treatment,
- The ambient air temperature is at or below 32 ~~degrees~~ °F, or ~~forecast to be so within the next 24 hours,~~
- ~~The majority of the pile is covered by ice or snow, or~~
- ~~If t~~**T**here is no material stored and no vehicle traffic at the temporary slag storage area.

Compliance Monitoring Requirements

D.13.6 Ambient Temperature Monitoring

To demonstrate the compliance status with Condition D.13.5, the Permittee shall maintain an ambient temperature monitor when ambient temperatures may drop below 32°F.

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

D.13.~~6~~**7** Record Keeping Requirement

To document the compliance status with Condition**s** D.13.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.13.5 – Compliance Determination Requirements, the Permittee shall maintain the following weekly records:

(1) The date and approximate time of each feedstock pile watering treatment.

(2) If a treatment is **not required and not performed pursuant to D.13.5** ~~skipped~~, records shall be maintained **documenting** ~~of~~ the reason (i.e.: the ambient temperature, **precipitation, or there is no material stored and no vehicle traffic at the temporary slag storage area.** ~~recent rainfall, snow, etc.~~)

Monitoring and Controls

Comment 70: Compliance Monitoring is not adequate to ensure Enforceability

Permit limits are enforced through monitoring. The hierarchy for specifying monitoring to determine compliance is: (1) continuous direct measurement where feasible; (2) initial and periodic direct measurement where continuous monitoring is not feasible; (3) use of indirect monitoring, e.g., surrogate monitoring, where direct monitoring is not feasible; and (4) equipment and work practice standards where direct and indirect monitoring are not feasible. U.S. EPA, *New Source Review Workshop Manual* ("NSR Manual"), Draft, October 1990 (*available at* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf), at H.5. For the reasons explained below, IDEM has ignored EPA's monitoring compliance hierarchy.

Work Practices do not constitute enforceable emissions limits

Equipment and work practice standards are not numerical emissions limits and are not enforceable at all times. They are the least preferred method of compliance monitoring and should be avoided when any other monitoring technique is feasible. IDEM proposes to control emission from at least six emissions units with work practices alone (EU-012A, EU-012P, EU-012Q, EU-012W, EU-012X, FUG-ROADS). IDEM should require more accurate monitoring techniques, or explain why other techniques are not feasible for each of these six units.

Response 70: IDEM has appropriately evaluated the monitoring options for each emission unit. Generally, many emission units do have requirements in the permit for CEMS, periodic testing, or surrogate monitoring such as pressure drop or continuous temperature monitoring.

Regarding the six units specifically identified in this comment, these are all fugitive particulate emissions sources for which many of the types of monitoring identified by the commenter are not possible. Also, the work practice standards for these units have been identified as BACT, and no more stringent controls were identified. The requirements imposed on these units are consistent with requirements for fugitive sources at other facilities and are appropriate for addressing fugitive dust.

No revisions to the draft permit are required as a result of this comment.

Comment 71: **Parametric monitoring is inadequate**
Parametric monitoring techniques measure proxies—such as temperature, pressure, or flow rates—to estimate emissions. The NSR Manual prefers continuous direct measurement or initial and periodic direct measurement over parametric monitoring. NSR Manual at H.5. Parametric monitoring should only be used when these other, more accurate techniques are not feasible. At least thirty-four emissions units rely on parametric monitoring (EU-012B, EU-012C, EU-012D, EU-012E, EU-012F, EU-012G, EU-012H, EU-012I, EU-012J, EU-012K, EU-012L, EU-012M, EU-012T, EU-012U, EU-012V, EU-012Z, EU-012AB, EU-012AC, EU-012AA, EU-012Y, EU-012N, EU-012O, EU-012R, EU-012S, EU-011A, EU-011B, EU-001, EU-002, EU-015A, EU-015B, EU-032, EU-024, EU-025, EU-033). IDEM should follow EPA's compliance monitoring hierarchy and require continuous direct monitoring or initial and periodic direct monitoring where feasible for these 34 emissions units.

Response 71: IDEM requires either direct emissions measurement or parametric monitoring for all emission units that have control device(s) in the permit. The type of monitoring used for each source and pollutant has been selected based on consideration of the magnitude of the emissions its expected variability, and the relative cost of the monitoring options. The permit also includes testing requirements for most of the emission units, except for the syngas hydrocarbon flare and acid gas flare that are extremely difficult to test. Stack testing of the ZLD Spray Dryer for NOx emission is not included because of its small size and low emissions rate.

The schedule of compliance testing, along with applicable parametric monitoring are sufficient to provide the information needed to evaluate continuous compliance with the emission limits at this source. Furthermore, all parametric monitoring requires that Indiana Gasification, LLC respond to and correct any deviations from the prescribed monitoring ranges. No revisions to the draft permit are required as a result of this comment.

Comment 72: **Direct periodic monitoring has not been used where feasible**
IDEM has failed to require sufficient direct periodic monitoring where feasible. It requires stack testing only once every five years for the Acid Gas Removal Units, Draft Permit at pdf p. 79, the Wet Sulfuric Acid plant trains, *Id.* at 86, and the ZLD Spray Dryer, *Id.* at 99. Stack testing is only required once for the natural gas-fired auxiliary boilers during the lifetime of the facility. *Id.* at 91. The permit should be revised to strengthen these and all other monitoring provisions.

Response 72: IDEM believes all permit terms and conditions are correct and the permit has sufficient testing and monitoring requirements to ensure compliance given the size of the emission units. Continuous or daily monitoring is required for many operating parameters at this facility, as shown in the TSD section called “Testing Requirements” (TSD page 40 of 43).

Much of the testing required by the permit will also be used to set compliance monitoring parameters that can then be monitored continuously, as in the case of the operating temperature for the RTO, or daily, as in the case of pressure drop across the scrubber for the WSA. However, IDEM may require compliance testing at any specific time when necessary to determine if these facilities are in compliance. If testing is required by IDEM, compliance shall be determined by a performance test conducted in accordance with Section C - Performance Testing. No revisions to the draft permit are required as a result of this comment. See also the response to Public Comment 29 regarding stack testing requirements for the auxiliary boilers.

Comment 73: Visible emissions notations are inadequate to monitor enforceable emission limits

IDEM proposes to monitor compliance for no less than 27 emission units with Visible Emissions Notations. Draft permit at pdf p. 60-61, 100. This requires a trained plant employee to record once a day whether emissions are “normal or abnormal.” *Id.* at 60. “Normal” is defined as “those conditions prevailing, or expected to prevail, at least 80% of the time the process is in operation, not counting startup or shutdown time.” *Id.*
In its New Source Review Manual, EPA explains that emission and operational limits “must be clearly expressed, easily measurable, and allow no subjectivity… Such limits should be of a short term nature, continuous *and enforceable*.” NSR Manual at H.5 (emphasis added). Visible emissions notations are not adequate to monitor enforceable emission limits for several reasons.

First, the testing is subjective. Different observers could make different notations. This problem would be cured if a recognized and repeatable test method were used to confirm the presence or absence of visible emissions and to quantify their magnitude. At a minimum, the permit should be revised to require a Method 9 test once a day during maximum operations.

Response 73: All of the BACT limits are numerical limits subject to stack testing to determine compliance, as already required by the permit. As such, the suggested Method 9 (or other) quantification of the opacity level would not be relevant and would not provide meaningful information for assuring compliance beyond what the permit currently requires.

The visible emission notation requirements are included in the permit as compliance monitoring, used to assure compliance between stack tests. The Method 9 training or its equivalent is not a requirement for making an abnormal or normal visible emissions determination, and Method 9 observations also have the potential to vary with the observer. IDEM requires that the employee be trained in the appearance and characteristics of normal visible emissions for that specific process.

It is also important to understand that visible emissions monitoring is a complement to other requirements. In the case of the failure of a single compartment baghouse or a wet dust extraction system, the associated process (and/or feed) must be shut down immediately. Further, depending on the control device, the permit requires pressure drop and/or flow rate monitoring, and the permit requires the Permittee to take reasonable response steps if abnormal emissions are observed or the pressure drop or flow rate is out of range. IDEM believes these monitoring requirements are sufficient enough for the source to comply with the limit given in the permit.

Comment 74: Second, the permit does not require that a relationship be established between visible emissions and the underlying PM/PM10 emission rates. Many of the emissions units monitored via visible emissions notations have very exacting emissions limits. *See, e.g.,* Draft Permit at pdf p. 90-91 (emission limits for ZLD Spray Dryer). These emission limits cannot be effectively monitored with such a subjective technique.

Response 74: The visible emission notation is not meant to exact a correlation with any emission limit. The visible emission notation is an indicator of continuous compliance to the limit given in the permit. Visible emissions observations and notations are designed to identify and correct potential problems with equipment or operating practices. While visible emissions observations serve this purpose well, it is generally not feasible to establish a direct and consistent relationship between visible observations and the emission rate of the source. Overall, monitoring the visible emissions and the operating parameters of control devices such as baghouses and dust extraction systems provides assurance that the units are operating similarly to when their emissions were established or tested.

Comment 75: Third, the definition of “trained employee” does not require a recognized and certified training program. Draft Permit at pdf p. 60. The permit requires only that the employee has worked at the plant for a month and “has been trained in the appearance and characteristics of normal visible emissions for that specific process.” *Id.* at 60. The permit should be revised to require that the “trained employee” successfully complete a training course equivalent to certification in Method 9.

Response 75: The Method 9 training or its equivalent is associated with determining a quantitative estimate of visible emissions and goes beyond this aspect of the permit. As a result, Method 9 training is not a requirement for making an abnormal or normal visible emissions determination. IDEM requires that the personnel be familiar with the operation at the source and what is normal or abnormal relative to visible emissions.

Comment 76: Fourth, the permit does not identify the information that would be recorded beyond a notation as to whether the emissions are normal or abnormal. *Id.* If these conditions are retained, they should be revised to require recording of the date, time of day, and weather conditions.

Response 76: According to Condition D.1.12(a), the source is already recording the day (date) of the visible emission notation reading. If there is an abnormal reading, the source will take response steps to correct the situation and record the steps taken to correct the out of range reading. The time of day and the weather conditions are not required. Therefore, there is no change to the permit condition.

Comment 77: Fifth, the observations are only made during normal daylight hours. This excludes all non-daylight hours, excluding from compliance many operating hours. This does not assure continuous compliance.

Response 77: The proper and accurate visible emission notation can only be taken during daylight. Any reading during non-daylight hours will not be accurate. Moreover, this reading is not feasible after dark. The source is already monitoring the pressure drop of the baghouse so this will be another indicator that the source is complying with the limit given by IDEM

BACT Analysis

Comment 78: The BACT analysis for the acid gas flare is incomplete and unsupported for several reasons. BACT for the flare is a flare minimization plan and flare best practices. Draft Permit at pdf p. 70-71. Flare minimization requires an investigation of the cause of the flaring event. Flare best practices require operation with no visible emissions, operation with a flame at all times, and continuous monitoring for the presence of a flame. There is no discussion of emission rates or limits for the flare.

Furthermore, IDEM did not make any attempt to set BACT for the flare specifically for periods of shutdown and malfunction. Periods of SSM cannot be ignored under the PSD program. BACT requirements, like PTE requirements, apply to SSM emissions. *See, e.g., In re Tallmadge Generating Station,* Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12, slip op. (EAB May 21, 2003) ("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown.") Exemption of a source "from any *concentration* limits during startup and shutdown," including short-term limits, is "potentially a…serious concern." *See In re Indeck-Niles Energy Center*, PSD Permit No. 364-00A; PSD Appeal No. 04-01, 2004 EPA App. LEXIS 36, n. 9 (EAB Sept. 30, 2004) (emphasis added).

Response 78: IDEM's draft permit does impose BACT requirements to the acid gas flare that pertain at all times, including periods of start-up, shutdown and malfunction. See Conditions D.3.4 through D.3.7 of the Draft Permit. In its BACT analysis supporting the draft permit, and consistent with the top-down approach to evaluating potential BACT control alternatives, IDEM evaluated BACT for flare emissions from the acid gas flare and identified the technically feasible BACT control alternatives, which are, depending on the pollutant at issue: flare design and proper operation; and/or process flaring minimization practices. See TSD pages 22-33 of 181. As a result, IDEM is specifically requiring that IG implement these measures as part of detailed work practice standard that will apply to the acid gas flare and associated equipment at all times. Specifically, the Draft Permit requires that IG implement and comply with the following BACT requirements: 1) Flare minimization plan; 2) Root cause investigation and corrective action of all malfunction events; 3) Flare "best practices," including designing and operating the flare to avoid visible emissions (except for periods not to exceed 5 minutes every two hours), operating the flare with a flame present at all time, and continuously monitoring the flare; and 4) Preventative Maintenance Plan.

IDEM, however, is not requiring acid gas flare emission limits or rates during normal operation, start-up or shutdown because there are not expected to be any emissions from the acid gas flare at those times, [except for pilot emissions]. As IG stated in its permit application, the acid gas flare is not expected to "have gas vented to it during normal operations or normal facility startups or shutdowns." Permit Application at p. 5-22. See also TSD pp. 23, 26, 29, 32 ("No non-emergency flaring is anticipated.") Accordingly, IDEM need not require that a specific emission rate or limit apply as there will be no expected emissions during those times. Further, the BACT analysis indicates that of the facilities reviewed with a similar acid gas flare, no other facility has any emission limits on startup, shutdown, or malfunctions.

IDEM also is not imposing specific emission limits or rates for malfunction event-related emissions. Given the inherently unpredictable nature of malfunction events and the inability to estimate associated emissions, numeric limits are infeasible. Further, BACT review anticipates the consideration of work practices as an appropriate control alternative. See, U.S. EPA, Draft New Source Review Workshop Manual, p. B.10 (1990) (emphasis added). As discussed above, IDEM is requiring IG to implement extensive BACT work practice requirements, including the implementation of flare emission minimization measures and the identification and correction of the root cause of any malfunction events contributing to acid gas flare emissions. This is again consistent with BACT requirements for other similar sources.

Footnote Comments

Comment 79: (a) We note that Section A and Section D claim that the information describing the source in Conditions A.1 through A.3 is not an enforceable condition. *See* Draft Permit page 14. However, the 0.015 lb/hr emission rate is based on the assumption that the emergency diesel generators are 1,341 hp. TSD pdf page at 427. If this is true that the description of the emergency diesel generators in the draft permit as 1,341 hp units is not an enforceable condition, then even the 0.015 lb/hr emission rate would be invalid because IG could install a larger diesel generator and have higher mass emissions than what is used in the modeling. This is true for all of the mass emission rates for other emission units determined based on the size of the emission unit, e.g. mmbtu/hr or hp, used in the modeling.

(b) We note that Section A and Section D claim that the information describing the source in Conditions A.1 through A.3 is not an enforceable condition. *See* Draft Permit page 14. However, the 14.58 lb/hr emission rate is based on the assumption that the emergency diesel generators are 1,341 hp. TSD pdf page at 427. If this is true that the description of the emergency diesel generators in the draft permit as 1,341 hp units is not an enforceable condition, then even the 14.58 lb/hr emission rate would be invalid because IG could install a larger diesel generator and have higher mass emissions than what is used in the modeling. This is true for all of the mass emission rates for other emission units determined based on the size of the emission unit, e.g. mmbtu/hr or hp, used in the modeling.

Response 79: IDEM believes that, the statement "The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions" contained in the Emission Unit Description box is correct and not misleading. The 1,341 hp is the permitted capacity for the emergency diesel generators and the Permittee may not construct the source inconsistent with the permit. Changes to the permitted capacities of the source are governed by the requirements of 326 IAC 2.

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T147-30464-00060. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions resulted in changes to the rule citations listed in the permit. These changes are not changes to the underlining provisions. The change is only to citations of these rules in Section A - General Information, Section A - Emission Units and Pollution Control Equipment Summary, Section A - Specifically Regulated Insignificant Activities, Section B - Preventative Maintenance Plan, Section B - Emergency Provisions, Section B - Operational Flexibility, Section C - Risk Management Plan, the Facility Descriptions, and Section D - Preventative Maintenance Plan.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5**(14)** ~~(15)~~][326 IAC 2-7-1(22)]

***

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5**(14)** ~~(15)~~]

***

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)] 326 IAC 2-7-5**(14)** ~~(15)~~]

***

B.12 Preventive Maintenance Plan [326 IAC 2-7-5~~(1),(3) and (13)~~ **(12)**] [~~326 IAC 2-7-6(1) and (6)~~][326 IAC 1-6-3]

***

B.13 Emergency Provisions [326 IAC 2-7-16]

***

(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)~~ **(8)** be revised in response to an emergency.

***

B.21 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)~~,~~ **or** (c)~~, or (e)~~ without a prior permit revision, if each of the following conditions is met:

***

(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)~~,~~ **or** (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)~~,~~ **and** (c)(1)~~, and (e)(2)~~.

***

C.14 Risk Management Plan [326 IAC 2-7-5(**11**~~12~~)] [40 CFR 68]

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Change 2: IDEM has moved to separate CAM language for Section C - compliance monitoring, REE, and reporting. This language is mainly verbatim from the CAM rule and is to clarify the Permittee's responsibility under CAM.

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

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

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

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

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

(b) **For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.**

(c) **For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.**

C.15 Response to Excursions or Exceedances **[40 CFR 64][326 IAC 3-8]**[326 IAC 2-7-5] [326 IAC 2-7-6]

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

……

(II)

(a) **CAM Response to excursions or exceedances.**

(1) **Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the 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. 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). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or 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**.

(2) 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, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or
(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) CAM recordkeeping requirements.
(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality

improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

Change 3: On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions included the incorporation of the U.S. EPA's definition of reasonable possibility. The permit previously cited to the EPA definition. Also, the revisions resulted in changes to other rule cites listed in the permit. And IDEM, OAQ has clarified the Permittee's responsibility with regard to record keeping.

C.18 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. **Support information includes the following:**

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.
(BB) The dates analyses were performed.
(CC) The company or entity that performed the analyses.
(DD) The analytical techniques or methods used.
(EE) The results of such analyses.
(FF) The operating conditions as existing at the time of sampling or measurement.

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.

……

(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)~~ **326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)**) that a "project" (as defined in 326 IAC 2-2-1(~~qq~~ **oo**) and/or 326 IAC 2-3-1(~~ll~~ **jj**)) 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~~ **dd**) and/or 326 IAC 2-3-1(~~z~~ **y**)) 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~~ **pp**) and/or 326 IAC 2-3-1(~~mm~~ **kk**)), the Permittee shall comply with following:

(1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(~~qq~~ **oo**) and/or 326 IAC 2-3-1(~~ll~~ **jj**)) 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~~ **pp**)(2)(A)(iii) and/or 326 IAC 2-3-1 (~~mm~~ **kk**)(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)~~ **326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)**) that a "project" (as defined in 326 IAC 2-2-1(~~qq~~ **oo**) and/or 326 IAC 2-3-1(~~ll~~ **jj**)) 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~~ **dd**) and/or 326 IAC 2-3-1(~~z~~ **y**)) 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~~ **pp**) and/or 326 IAC 2-3-1(~~mm~~ **kk**)), the Permittee shall comply with following:

....

C.19 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3] **[40 CFR 64][326 IAC 3-8]**

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

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

....

Change 4: The ZLD-Spray Dryer, identified as EU-032 is a small unit that is not subject to CAM. Therefore the CAM citation has been removed from Conditions D.8.15, D.8.16 and D.8.17 of the permit accordingly.

D.8.15 Broken or Failed Bag Detection ~~[40 CFR 64]~~

(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).

....

D.8.16 Visible Emissions Notations ~~[40 CFR 64]~~

(a) Visible emission notations of the ZLD-Spray Dryer, identified as EU-032 stack exhausts (S-014) shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

....

D.8.17 Parametric Monitoring ~~[40 CFR 64]~~

In order to demonstrate the compliance status with Condition D.8.4, the Permittee shall record the pressure drop across the baghouse used in conjunction with the ZLD-Spray Dryer operations at least once per day when this unit is in operation. When the pressure drop across the baghouse is outside the normal range of 1.0 and 5.0 inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

...

Change 5: Any finalized requirements of the Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, proposed by U.S. EPA on April 13, 2012 (77 Fed. Reg. 22392), will not apply to any emission units at the source. The requirements of this proposed rule will apply to electric generating units that commence construction after the publication date of the proposed rule with a base load rating of more than 73 MW (250 MMBtu/hr). The proposed rule defines an "electric generating unit" as "any steam electric generating unit or stationary combustion turbine 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." While the two auxiliary boilers exceed the 250 MMBtu/hr applicability threshold, they are not considered "electric generating units" because they are not constructed for the purpose of supplying more than one-third of their potential electric output capacity to a utility power distribution system for sale, and Permit Condition D.6.9 limits operation of the auxiliary boilers to less than one-third of their potential electric output capacity.

Therefore, it is appropriate to add the following to Condition B.14(b) – Permit Shield:

The typo in Condition B.14 - Permit Shield has been corrected and the non applicable portion of the carbon dioxide (CO2e) NSPS has been added to the Permit Shield.

B.14 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

....

(b) In addition to the nonapplicability determinations set forth in Section D of this permit, the IDEM, OAQ has made the following determinations regarding this source.

....

(4) **40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978:**

(A) This source is not subject to 40 CFR Part 60, Subpart D**a** because the auxiliary boilers, which can supply steam to an electric generating steam turbine are steam-generating units, but they are not considered an electric utility unit because they will not supply more than 1/3 of its potential electrical output capacity to any utility power distribution system.

(B) This source is not subject to 40 CFR Part 60, Subpart D**a** because the thermal oxidizers (EUs 007A, B) or gasifier pre-heat burners (EUs 008A-E) since they do not meet the definition of an electric utility steam generating unit. Specifically, the thermal oxidizers and the pre-heat burners do not generated steam, and thus are not steam generating units.

....

(11) Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units: The source will not be subject to any finalized requirements of the "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units" proposed by U.S. EPA on April 13, 2012 (77 Fed. Reg. 22392), because no electric generating unit at the facility is a 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.

(~~11~~**12**) **326 IAC 24 Clean Air Interstate Rule (CAIR):** The source is not subject to the requirements of 326 IAC 24 or the federal final rule issued on August 8, 2011 limiting the interstate transport of NOx and SO2 (76 Fed. Reg. 48208 et seq. Pursuant to 326 IAC 24-1(b)(1)(B) and the applicability requirements of 76 Fed. Reg. 48208, neither rule applies to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale.

(~~12~~**13**) **40 CFR Part 72-78 Acid Rain Program:** This source is not subject to the requirements of 40 CFR Part 72-78 because it does not sell greater than 1/3 **of** its generated ~~electric~~ **electricity**.

....

Change 6: IDEM, OAQ has updated the language in Condition D.2.9 (now D.2.10) - Record Keeping Requirement in the permit accordingly.

D.2.~~9~~**10** Record Keeping Requirements

....

~~(c) To document the compliance status with the shutdown emission limits for SO2 in Condition D.2.4(3)(B), the Permittee shall maintain records of the total number of minutes for each shutdown flaring event.~~

(~~d~~**c**) To document the compliance status with Condition D.2.4, the Permittee shall maintain records of the date, time, and total number of minutes for each startup **and shutdown** flaring event.

…..

Change 7: IDEM, OAQ has updated and clarify the language in Condition D.4.23 now D.4.24 - Record Keeping Requirement in the permit accordingly.

D.4.2~~3~~**4** Record Keeping Requirements

(a) In order to document the compliance status with Condition**s** D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, D.4.6 – SO~~2~~ PSD BACT, D.4.9 - GHGs PSD BACT, D.4.13 – ~~Compliance Determination Requirements~~ **PM, PM_{10}, and $PM_{2.5}$ Calculations**, D.4.15 – Sulfur Dioxide Control **and Calculations**, and D.4.16 – ~~Compliance Determination Requirements~~ **Greenhouse Gases (GHGs) Calculations**, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the RTOs for the Acid Gas Removal (AGR) Unit vents.

....

(c) To document the compliance status with Condition D.4.10 – Alternate Emissions Limitation During Gasifier Startup Flaring, the Permittee shall maintain monthly records of the NOx emissions during gasifier startup flaring.

…..

Change 8: IDEM, OAQ has updated the language in Condition D.8.11 - Compliance Determination Requirement in the permit.

D.8.11 Compliance Determination Requirements

In order to ensure compliance with Conditions **D.8.5 – CO PSD BACT,** D.8.6 - SO_2 PSD BACT**, D.8.7 – NOx PSD BACT,** and D.8.8(a) - GHGs PSD BACT, the Permittee shall only use natural gas or SNG in the ZLD-Spray Dryer (EU-032).

Change 9: IDEM has included new Condition D.2.5 to clarify the area source status for this source.

D.2.5 Hazardous Air Pollutants (HAPs) Minor Limits

The single HAP and total HAP from the syngas hydrocarbon flare identified as EU-001 shall be limited by compliance with the SO_2 emission limit is Condition D.2.4(3) and, combined with the potential to emit HAP emissions from all other emission units, this requirement will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

……

Change 10: IDEM has revised these emission unit descriptions in Section A.2, A.3, D1 through D.18 and E1 through E.6 of the permit. And the word "to be permitted in 2012" has been changed to "permitted in 2012" throughout the permit.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

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

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, ~~to be~~ permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

……

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, ~~to be~~ permitted in 2012, with ~~methanol, H_2S, COS,~~ **HAP, VOC** and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stack, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, ~~to be~~ permitted in 2012, with NO_x, ~~SO_2, H_2SO_4~~ emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and **particulate, H_2SO_4, and SO_2 emissions controlled by** two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, **and particulate and H_2SO_4 emissions controlled by a high efficiency mist eliminator,** exhausting through two (2) stacks, identified as S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

……

(I) One (1) ZLD-Spray Dryer, ~~to be~~ permitted in 2012, nominally rated at 5.6 MMBtu/hr with ~~PM~~ **particulate** emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

Change 11: A reporting form has been added to the permit to report the emission of the Carbonyl Sulfide (Single HAP).

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

Part 70 Quarterly Report

Source Name: **Indiana Gasification, LLC**
Source Address: **CR 200 N and Base Road, Rockport, Indiana 47635**
Part 70 Permit No.: **T147-30464-00060**
Facility: **Acid Gas Removal Unit Vents (EU-007A/B)**
Parameter: **Single HAPs Emissions (Carbonyl Sulfide)**
Limit: **less than 9 tons per twelve (12) consecutive month period with compliance determined at the end of each month.**

QUARTER : **YEAR:**

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

☐ **No deviation occurred in this quarter.**

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

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

Appendix A: Emissions Calculations
Emission Summary (Total HAPS)

Emissions shown are those limited by permit conditions.

Emission unit	Total HAPs (tons/year)	
Syngas hydrocarbon Flare (001)	0.0049	
Acid Gas Flare (002)	0.0022	
Auxiliary Boiler (005A-B)	1.40	
Acid Gas Recovery Unit (007A-B)	17.00	
Gasifier Preheat Burners (008A-E)	0.10	
Emergency Diesel Generator (009A-B)	0.00077	Revised to Include HAPs per AP42
Emergency Firewater Engine (010A-C)	0.00122	Revised to Include HAPs per AP42
Process Area Solid Feedstock (011)	0	
Incoming Solid Feedstock Handling (012A-AC)	0	
Rod Mill (013A-D)	0	
Wet Sulfuric Acid Plant (015A-B)	0	
Cooling Tower - ASU (016A)	0	
Cooling Tower - Main (016B)	0	
ASU Molecular Sieve Regeneration (017A-B)	0	
Slag Sump (023A-E)	0	
Methanol De-Inventory Storage Tank (024)	0.16	
Fresh Methanol Storage Tank (025)	0.13	
Sour Water Stripper Surge Tank (026)	0	
Sulfuric Acid Storage Tank (027A-F)	0	
Diesel Fuel Storage Tank (029)	0.07	
Gasoline Fuel Storage Tank (030)	0	
Triethylene Glycol Storage Tank (031)	0	
ZLD Spray Dryer (032)	0.046	
ZLD Inert Gas Vent (033)	0	
EU-034A and 034C	0	
Fugitve Emissions		
Gasification, Shift Conv. AGR, methanation (FUG)	0.381	
Fugitive Emission - WSA (FUG-WSA)	0	
Plant Haul Roads (FUG-ROAD)	0	
Electric Circuit Breakers (FUG-SF6)	0	
Total Emissions	19.30	

Estimated HAP Emissions From Emergency Diesel Engines (Emergency Generators EU# 009A/B, Fire Water Pump Engine EU 010A/B/C)

EU#	Emissions Unit	Rating		Frequency (Unlimited)		Emission Factor		HAPs (TPY)
009A	Emergency Diesel Power Generator A	1,341	HP	500	hr/yr	1.10E-05	lb/hp-hr	0.00369
009B	Emergency Diesel Power Generator B	1,341	HP	500	hr/yr	1.10E-05	lb/hp-hr	0.00369
010A	Fire Water Diesel Pump A	575	HP	500	hr/yr	2.71E-05	lb/hp-hr	0.00390
010B	Fire Water Diesel Pump B	575	HP	500	hr/yr	2.71E-05	lb/hp-hr	0.00390
010C	Fire Water Diesel Pump C	575	HP	500	hr/yr	2.71E-05	lb/hp-hr	0.00390
							Total HAPs	0.01908

These calculations assume unlimited operation of engines up to 500 hrs/yr each.

Emergency Engine HAPs factors
Internal Combustion, > 600 HP
AP-42 Section 3.4 Table 3.4-2 & 3.4-3

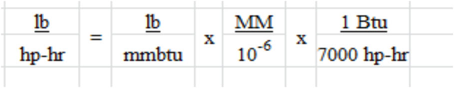
HAP	Factor	
Benzene	7.76E-04	lb/mmBtu
Toluene	2.81E-04	lb/mmBtu
Xylenes	1.93E-04	lb/mmBtu
Formaldehyde	7.89E-05	lb/mmBtu
Acetaldehyde	2.52E-05	lb/mmBtu
Acrolein	7.88E-06	lb/mmBtu
Naphthalene	1.30E-04	lb/mmBtu
Acenaphthylene	9.23E-06	lb/mmBtu
Acenaphthene	4.68E-06	lb/mmBtu
Fluorene	1.28E-05	lb/mmBtu
Phenanthrene	4.08E-05	lb/mmBtu
Anthracene	1.23E-06	lb/mmBtu
Fluoranthene	4.03E-06	lb/mmBtu
Pyrene	3.71E-06	lb/mmBtu
Benz(a)anthracene	6.22E-07	lb/mmBtu
Chrysene	1.53E-06	lb/mmBtu
Benzo(b)fluoranthene	1.11E-06	lb/mmBtu
Benzo(k)fluoranthene	2.18E-07	lb/mmBtu
Benzo(a)pyrene	2.57E-07	lb/mmBtu
Indeno(1,2,3-cd)pyrene	4.14E-07	lb/mmBtu
Dibenz(a,h)anthracene	3.46E-07	lb/mmBtu
Benzo(g,h,l)perylene	5.56E-07	lb/mmBtu
Total	1.57E-03	lb/mmBtu
Total in different units	1.10E-05	lb/hr-hr

Emergency Engine HAPs factors
Internal Combustion, < 600 HP
AP-42 Section 3.3 Table 3.3-2

HAP	Factor	
Benzene	9.33E-04	lb/mmBtu
Toluene	4.09E-04	lb/mmBtu
Xylenes	2.85E-04	lb/mmBtu
1,3-Butadiene	3.91E-05	lb/mmBtu
Formaldehyde	1.18E-03	lb/mmBtu
Acetaldehyde	7.67E-04	lb/mmBtu
Acrolein	9.25E-05	lb/mmBtu
Naphthalene	8.48E-05	lb/mmBtu
Acenaphthylene	5.06E-06	lb/mmBtu
Acenaphthene	1.42E-06	lb/mmBtu
Fluorene	2.92E-05	lb/mmBtu
Phenanthrene	2.94E-05	lb/mmBtu
Anthracene	1.87E-06	lb/mmBtu
Fluoranthene	7.61E-06	lb/mmBtu
Pyrene	4.78E-06	lb/mmBtu
Benzo(a)anthracene	1.68E-06	lb/mmBtu
Chrysene	3.53E-07	lb/mmBtu
Benzo(b)fluoranthene	9.91E-08	lb/mmBtu
Benzo(k)fluoranthene	1.55E-07	lb/mmBtu
Benzo(a)pyrene	1.88E-07	lb/mmBtu
Indeno(1,2,3-cd)pyrene	3.75E-07	lb/mmBtu
Dibenz(a,h)anthracene	5.83E-07	lb/mmBtu
Benzo(g,h,l)perylene	4.89E-07	lb/mmBtu
Total	3.87E-03	lb/mmBtu
	2.71E-05	lb/hr-hr

Conversion Factor	7,000	Btu/hp-hr

AP-42 Section 3.3 Table 3.3-1 reference a & Section 3.4 Table 3.4-1 reference e



$$\frac{\text{lb}}{\text{hp-hr}} = \frac{\text{lb}}{\text{mmbtu}} \times \frac{\text{MM}}{10^{-6}} \times \frac{1\ \text{Btu}}{7000\ \text{hp-hr}}$$

Estimated HAP Emissions From Emergency Diesel Engines (Emergency Generators EU# 009A/B, Fire Water Pump Engine EU 010A/B/C)

EU#	Emissions Unit	Rating		Frequency - Limited by Permit		Emission Factor		HAPs (TPY)
009A	Emergency Diesel Power Generator A	1,341	HP	52	hr/yr	1.10E-05	lb/hp-hr	0.00038
009B	Emergency Diesel Power Generator B	1,341	HP	52	hr/yr	1.10E-05	lb/hp-hr	0.00038
010A	Fire Water Diesel Pump A	575	HP	52	hr/yr	2.71E-05	lb/hp-hr	0.00041
010B	Fire Water Diesel Pump B	575	HP	52	hr/yr	2.71E-05	lb/hp-hr	0.00041
010C	Fire Water Diesel Pump C	575	HP	52	hr/yr	2.71E-05	lb/hp-hr	0.00041
							Total HAPs	0.00198

These calculations assume each engine is limited by permit to 52 hrs/yr each.

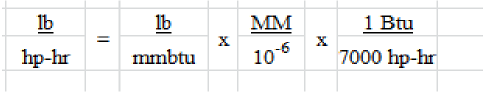
Emergency Engine HAPs factors
Internal Combustion, > 600 HP
AP-42 Section 3.4 Table 3.4-2 & 3.4-3

HAP	Factor	
Benzene	7.76E-04	lb/mmBtu
Toluene	2.81E-04	lb/mmBtu
Xylenes	1.93E-04	lb/mmBtu
Formaldehyde	7.89E-05	lb/mmBtu
Acetaldehyde	2.52E-05	lb/mmBtu
Acrolein	7.88E-06	lb/mmBtu
Naphthalene	1.30E-04	lb/mmBtu
Acenaphthylene	9.23E-06	lb/mmBtu
Acenaphthene	4.68E-06	lb/mmBtu
Fluorene	1.28E-05	lb/mmBtu
Phenanthrene	4.08E-05	lb/mmBtu
Anthracene	1.23E-06	lb/mmBtu
Fluoranthene	4.03E-06	lb/mmBtu
Pyrene	3.71E-06	lb/mmBtu
Benz(a)anthracene	6.22E-07	lb/mmBtu
Chrysene	1.53E-06	lb/mmBtu
Benzo(b)fluoranthene	1.11E-06	lb/mmBtu
Benzo(k)fluoranthene	2.18E-07	lb/mmBtu
Benzo(a)pyrene	2.57E-07	lb/mmBtu
Indeno(1,2,3-cd)pyrene	4.14E-07	lb/mmBtu
Dibenz(a,h)anthracene	3.46E-07	lb/mmBtu
Benzo(g,h,l)perylene	5.56E-07	lb/mmBtu
Total	1.57E-03	lb/mmBtu
Total in different units	1.10E-05	lb/hr-hr

Emergency Engine HAPs factors
Internal Combustion, < 600 HP
AP-42 Section 3.3 Table 3.3-2

HAP	Factor	
Benzene	9.33E-04	lb/mmBtu
Toluene	4.09E-04	lb/mmBtu
Xylenes	2.85E-04	lb/mmBtu
1,3-Butadiene	3.91E-05	lb/mmBtu
Formaldehyde	1.18E-03	lb/mmBtu
Acetaldehyde	7.67E-04	lb/mmBtu
Acrolein	9.25E-05	lb/mmBtu
Naphthalene	8.48E-05	lb/mmBtu
Acenaphthylene	5.06E-06	lb/mmBtu
Acenaphthene	1.42E-06	lb/mmBtu
Fluorene	2.92E-05	lb/mmBtu
Phenanthrene	2.94E-05	lb/mmBtu
Anthracene	1.87E-06	lb/mmBtu
Fluoranthene	7.61E-06	lb/mmBtu
Pyrene	4.78E-06	lb/mmBtu
Benzo(a)anthracene	1.68E-06	lb/mmBtu
Chrysene	3.53E-07	lb/mmBtu
Benzo(b)fluoranthene	9.91E-08	lb/mmBtu
Benzo(k)fluoranthene	1.55E-07	lb/mmBtu
Benzo(a)pyrene	1.88E-07	lb/mmBtu
Indeno(1,2,3-cd)pyrene	3.75E-07	lb/mmBtu
Dibenz(a,h)anthracene	5.83E-07	lb/mmBtu
Benzo(g,h,l)perylene	4.89E-07	lb/mmBtu
Total	3.87E-03	lb/mmBtu
	2.71E-05	lb/hr-hr

Conversion Factor 7,000 Btu/hp-hr
AP-42 Section 3.3 Table 3.3-1 reference a & Section 3.4 Table 3.4-1 reference e



$$\frac{\text{lb}}{\text{hp-hr}} = \frac{\text{lb}}{\text{mmbtu}} \text{ x } \frac{\text{MM}}{10^{-6}} \text{ x } \frac{\text{1 Btu}}{\text{7000 hp-hr}}$$

FLARE SOURCES

NAME: Hydrocarbon / Gasifier Start-up Flare *"Not-Limited" by Permit Limits"*
(With S/D HAPS added)

Unit ID: 001

STACK DATA

HEIGHT 300 ft
DIAMETER 6 ft

EMISSIONS: Scenario 1: Gasifier Start-Up Syngas Flaring

hr/yr = 8760
Firing Rate = 861.7 MMBtu/hr
CO DRE 0 %

Pollutant	H2S in Syngas lb-mol/hr	COS in Syngas lb-mol/hr	Raw Syngas Flared lb-mol/hr	CO in Syngas Mol %	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	--	--	--	--	6.42	6.42	28.12
$PM_{2.5}$					0.09	0.09	0.41
SO_2	0.01	0	--	--	0.70	0.70	3.045
NOx	--	--	--	--	86.17	86.17	377.42
CO	--	--	18237.12	13.50	68939.73	68939.73	301956.00
H2S (TAP)	0.01	--	--	--	0.01	0.01	0.03
COS (TAP)(VOC)	--	0.00	--	--	0.00	0.00	0.00
Other VOC	--	--	--	--	0.09	0.09	0.41
Total VOC					0.09	0.09	0.41

EMISSIONS: Scenario 2: Gasifier Start-Up Flare Pilot Burners Operating

hr/yr = 8,760
Pilot Firing Rate = 0.27 MMBtu/hr
AP-42 Heating Value = 1,020 Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.0020	0.0020	0.0087
$PM_{2.5}$	0.0019	0.0019	0.0081
SO_2	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.06
VOC	0.005	0.005	0.02
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

TOTAL STARTUP FLARING AND PILOT

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	6.422	6.42	28.13
$PM_{2.5}$	0.095	0.09	0.41
SO_2	0.70	0.70	3.046
NOx	86.22	86.22	377.65
CO	68939.74	68939.74	301956.05
H2S (TAP)	0.013	0.01	0.06
COS (TAP)(VOC)	0.00	0.00	0.00
Total VOC	0.0982	0.09	0.43
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

Calculations:

Scenario 1:

Emissions (SO2)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) + COS in Syngas (lb-mol/hr) X 64.063 lb/mol
Emissions (CO)(Avg. lb/hr)=(Raw Syngas flared (lbmols/hr) X CO in Syngas (mol %)/100) X 28.01 lb/mol X (100 - CO DRE)/100
Emissions (H2S)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) X 34.08 lb/mol X 2/100
Emissions (COS)(Avg. lb/hr)=COS in Syngas (lb-mol/hr) X 60.0764 lb/mol X 2/100
Emissions (NOx, PM_{10}, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenarios 2 and 3:

Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions-Pilot Case (SO2, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenario 1	NOx	PM_{10}	VOC
Factor (lb/MMBtu)	0.100	0.007	0.0001

Sources: NOx and PM_{10} for Syngas are based on values from vendor supplied data. VOC for Syngas = 2% of AP-42 Section 1.4 "Natural Gas Combustion" Table 1.4-2

Scenario 2 Factor (lb/MMscf)	PM_{10}	SO_2
	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Scenario 2 Factor (lb/MMBtu)	NOx	CO	VOC
	0.200	0.050	0.020

Sources: NOx and CO, and VOC are based on values from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

DRE for H2S and COS is considered as 98%.
DRE for CO is considered as 99.5%.
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs for natural gas to the pilot are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4. Flared gas is primarily CO and H2 - HAPs assumed negligable.
Scenario 1: Gasifier Start-up Syngas Flaring
Scenario 2: Gasifier Start-up Flare Pilot Burners Operating
Scenario 3: Normal Operations-Purge Gas and Pilot Gas Flaring

Number Shutdown Flaring Events / year = 15
Flaring Event Duration (hrs) = 3
Firing Rate (MMBtu/Event) = 34.26
Total MMBtu/yr 513.9

SHUTDOWN FLARING

Pollutant	Average Emissions lb/event	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.260	0.09	0.002
$PM_{2.5}$	0.260	0.09	0.002
SO_2	255.62	85.21	1.917
NOx	3.43	1.14	0.026
CO	21.22	7.07	0.159
H2S (TAP)	2.660	0.89	0.020
COS (TAP)(VOC)	0.20	0.07	0.002
VOC	0.0037	0.00	0.000
Total HAPS	0.3728	0.12	0.0028

Total HAPs Emiss. Factor shown on separate page: 1.09E-02 lb/MMBtu

GHG Emissions from Gasifier Start-up

The feed to the gasifier flare during the start-up of a gasifier contains CO and CO2, but no other carbon compounds. A mass balance was used to determine the CO2 and N2O emissions. There will be no CH4 emissions. The GHG Subpart Y (Refinery) flare equations are not applicable; however, the Subpart Y equation for N2O will be used to conservatively estimate N2O emissions.

	lb/hr	TPY	MT/yr
CO2 for Gasifier Flare =	185,818.1	813,883.3	738354.9

Equation Y-5

N_2O = Annual nitrous oxide emissions from flared gas (metric ton N_2O/year)
CO_2 = Emission rate of CO_2 from flared gas calculated (metric ton/year)
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of subpart C (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu) = 0.0006
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

N2O for Gasifier Flare = 7.384 MT

GHG Emissions from Pilot

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123.2 MT

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Hydrocarbon / Gasifier Start-up Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

Startup

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	738,355	1	738,355
CH4	0	21	0
N2O	7.384	310	2,288.9
		TOTAL =	740,644

816,190 TPY CO2

Shutdown

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	36,918	1	36,918
CH4	0	21	0
N2O	0.369	310	114.4
		TOTAL =	37,032

40,809 TPY CO2

Shutdown flared gas volume on an annual basis is 5% of startup flared gas volume.

Pilot

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	123.2	1	123.2
CH4	0.0023	21	0.05
N2O	0.0002	310	0.07
		TOTAL =	123.3

136 TPY CO2

NAME Hydrocarbon / Gasifier Start-up Flare *"Limited by Permit Limits"* Unit ID: 001
(With S/D HAPS added)

STACK DATA

HEIGHT 300 ft
DIAMETER 6 ft

EMISSIONS: Scenario 1: Gasifier Start-Up Syngas Flaring

hr/yr = 135
Firing Rate = 861.7 MMBtu/hr
CO DRE 99.5 %

Pollutant	H2S in Syngas lb-mol/hr	COS in Syngas lb-mol/hr	Raw Syngas Flared lb-mol/hr	CO in Syngas Mol %	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	--	--	--	--	6.42	6.42	0.43
PM$_{2.5}$					6.02	6.02	0.41
SO$_2$	0.01	0	--	--	0.70	0.70	0.047
NOx	--	--	--	--	86.17	86.17	5.82
CO	--	--	18237.12	13.50	344.70	344.70	23.27
H2S (TAP)	0.01	--	--	--	0.01	0.01	0.00
COS (TAP)(VOC)	--	0.00	--	--	0.00	0.00	0.00
Other VOC	--	--	--	--	0.09	0.09	0.01
Total VOC					0.09	0.09	0.01

EMISSIONS: Scenario 2: Gasifier Start-Up Flare Pilot Burners Operating

hr/yr = 8,760
Pilot Firing Rate = 0.27 MMBtu/hr
AP-42 Heating Value = 1,020 Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	0.0020	0.0020	0.0087
PM$_{2.5}$	0.0019	0.0019	0.0081
SO$_2$	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.06
VOC	0.005	0.005	0.02
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

TOTAL STARTUP FLARING AND PILOT

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	0.101	6.42	0.44
PM$_{2.5}$	0.095	6.02	0.41
SO$_2$	0.01	0.70	0.048
NOx	1.38	86.22	6.05
CO	5.33	344.71	23.33
H2S (TAP)	0.005	0.01	0.02
COS (TAP)(VOC)	0.00	0.00	0.00
Total VOC	0.0067	0.09	0.03
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

Calculations:
Scenario 1:
Emissions (SO2)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) + COS in Syngas (lb-mol/hr) X 64.063 lb/mol
Emissions (CO)(Avg. lb/hr)=(Raw Syngas flared (lbmols/hr) X CO in Syngas (mol %)/100) X 28.01 lb/mol X (100 - CO DRE)/100
Emissions (H2S)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) X 34.08 lb/mol X 2/100
Emissions (COS)(Avg. lb/hr)=COS in Syngas (lb-mol/hr) X 60.0764 lb/mol X 2/100
Emissions (NOx, PM$_{10}$, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.
Scenarios 2 and 3:
Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions-Pilot Case (SO2, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenario 1	NOx	PM$_{10}$	VOC
Factor (lb/MMBtu)	0.100	0.007	0.0001

Sources: NOx and PM_{10} for Syngas are based on values from vendor supplied data. VOC for Syngas = 2% of AP-42 Section 1.4 "Natural Gas Combustion" Table 1.4-2

Scenario 2 Factor (lb/MMscf)	PM_{10}	SO_2
	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Scenario 2 Factor (lb/MMBtu)	NOx	CO	VOC
	0.200	0.050	0.020

Sources: NOx and CO, and VOC are based on values from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

DRE for H2S and COS is considered as 98%.
DRE for CO is considered as 99.5%.
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs for natural gas to the pilot are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4. Flared gas is primarily CO and H2 - HAPs assumed negligable.
Scenario 1: Gasifier Start-up Syngas Flaring
Scenario 2: Gasifier Start-up Flare Pilot Burners Operating
Scenario 3: Normal Operations-Purge Gas and Pilot Gas Flaring

Number Shutdown Flaring Events / year = 15
Flaring Event Duration (hrs) = 3
Firing Rate (MMBtu/Event) = 34.26

SHUTDOWN FLARING

Pollutant	Average Emissions lb/event	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.260	0.09	0.002
$PM_{2.5}$	0.260	0.09	0.002
SO_2	255.62	85.21	1.917
NOx	3.43	1.14	0.026
CO	21.22	7.07	0.159
H2S (TAP)	2.660	0.89	0.020
COS (TAP)(VOC)	0.20	0.07	0.002
VOC	0.0037	0.00	0.000
Total HAPS	0.3728	0.12	0.0028

Total HAPs Emiss. Factor shown on separate page: 1.09E-02 lb/MMBtu

GHG Emissions from Gasifier Start-up

The feed to the gasifier flare during the start-up of a gasifier contains CO and CO2, but no other carbon compounds. A mass balance was used to determine the CO2 and N2O emissions. There will be no CH4 emissions. The GHG Subpart Y (Refinery) flare equations are not applicable; however, the Subpart Y equation for N2O will be used to conservatively estimate N2O emissions.

	lb/hr	TPY	MT/yr
CO2 for Gasifier Flare =	185,818.1	12,542.7	11378.8

Equation Y-5

N_2O = Annual nitrous oxide emissions from flared gas (metric ton N_2O/year)
CO_2 = Emission rate of CO_2 from flared gas calculated (metric ton/year)
EmF_{N2O} = Default N_2O emission factor for "Petroleum Products" from Table C-2 of subpart C (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu) = 0.0006
EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

N2O for Gasifier Flare = 0.114 MT

GHG Emissions from Pilot

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123.2 MT

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Hydrocarbon / Gasifier Start-up Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

Startup

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	11,379	1	11,379
CH4	0	21	0
N2O	0.114	310	35.3
		TOTAL =	11,414

12,578 TPY CO2

Shutdown

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	569	1	569
CH4	0	21	0
N2O	0.006	310	1.8
		TOTAL =	571

629 TPY CO2

Shutdown flared gas volume on an annual basis is 5% of startup flared gas volume.

Pilot

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	123.2	1	123.2
CH4	0.0023	21	0.05
N2O	0.0002	310	0.07
		TOTAL =	123.3

136 TPY CO2

Hydrocarbon Flare Shutdown Emissions HAP Calculations

Emission Point	Emissions Unit	Shutdown Gas Flow		Emission Factor		HAPs (TPY)
001	Hydrocarbon Flare Shutdown Emissions	514	mmBtu/year	1.09E-02	lb/mmBtu	0.0028

-

HAPs factors for Syngas Flaring during Shutdowns

HAP	Factor		Basis of Factor
2-Methylnaphthalene	2.35E-08	lb/mmBtu	AP-42, Table 1.4-4
3-Methylchloranthrene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
7,12-Dimethylbenz(a)anthracene	1.57E-08	lb/mmBtu	AP-42, Table 1.4-4
Acenaphthene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Acenaphthylene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Anthracene	2.35E-09	lb/mmBtu	AP-42, Table 1.4-4
Benz(a)anthracene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Benzene	2.06E-06	lb/mmBtu	AP-42, Table 1.4-4
Benzo(a)pyrene	1.18E-09	lb/mmBtu	AP-42, Table 1.4-4
Benzo(b)fluoranthene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Benzo(g,h,i)perylene	1.18E-09	lb/mmBtu	AP-42, Table 1.4-4
Benzo(k)fluoranthene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Chrysene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Dibenzo(a,h)anthracene	1.18E-09	lb/mmBtu	AP-42, Table 1.4-4
Dichlorobenzene	1.18E-06	lb/mmBtu	AP-42, Table 1.4-4
Fluoranthene	2.94E-09	lb/mmBtu	AP-42, Table 1.4-4
Fluorene	2.75E-09	lb/mmBtu	AP-42, Table 1.4-4
Formaldehyde	7.35E-05	lb/mmBtu	AP-42, Table 1.4-4
Hexane	1.76E-03	lb/mmBtu	AP-42, Table 1.4-4
Indeno(1,2,3-cd)pyrene	1.76E-09	lb/mmBtu	AP-42, Table 1.4-4
Naphthalene	5.98E-07	lb/mmBtu	AP-42, Table 1.4-4
Phenanathrene	1.67E-08	lb/mmBtu	AP-42, Table 1.4-4
Pyrene	4.90E-09	lb/mmBtu	AP-42, Table 1.4-4
Toluene	3.33E-06	lb/mmBtu	AP-42, Table 1.4-4

(Continued on Next Page)

HAPs factors for Syngas Flaring during Shutdowns (Continued)

HAP	Factor		Basis of Factor
Hydrochloric Acid[1]	8.85E-03	lb/mmBtu	Note 1
Arsenic[2]	1.60E-06	lb/mmBtu	Note 2
Beryllium[2]	1.80E-07	lb/mmBtu	Note 2
Cadmium[2]	2.20E-07	lb/mmBtu	Note 2
Chromium[2]	1.00E-06	lb/mmBtu	Note 2
Cobalt[2]	8.24E-08	lb/mmBtu	Note 2
Manganese[2]	1.10E-06	lb/mmBtu	Note 2
Mercury[3]	1.71E-04	lb/mmBtu	Note 3
Nickel[2]	1.10E-06	lb/mmBtu	Note 2
Selenium[2]	1.50E-06	lb/mmBtu	Note 2
Lead[2]	4.00E-06	lb/mmBtu	Note 2
Total HAPs for Syngas combustion	1.09E-02	lb/mmBtu	

<u>Shutdown Syngas Flaring Emissions factor basis.</u>

Note 1 - HCL emissions are based on conservative assumption of 10 ppm HCL in syngas per

Note 2 - Metal HAP factors (except mercury) are from Proposed Duke Edwardsport IGCC ,

Note 3 - Mercury content of syngas is .0352 ppmv per engineering estimate.

Note 4 - Organic HAPs conservatively assumed equal to AP42 for NG combustion

Fugitive Emissions: Additional HAP Calculations for Emiss. Unit FUG and FUG-WSA

Specifically, the below caluclations quantify HAPs from syngas piping leaks of HCl and trace metals. Other HAPs present in Fugitive Leaks from Emission Unit FUG and FUG-WSA (e.g. Methanol, COS) are documented on a separate spreadsheet which was part of the original IG Application and IDEM's proposed TSD document.

HCl[1]

Fugitive Source	Component Count	HAP Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	270	0.0010%	0.0089	0.00002	0	0.00002	0.0001
Flanges	650	0.0010%	0.0029	0.00002	0	0.00002	0.0001
Compressor Seals	0	0.0010%	0.5027	0	0	0	0
Pump Seals	0	0.0010%	0.0386	0	0	0	0
Relief Valves	36	0.0010%	0.2293	0.00008	0	0.0001	0.0004
Sample Connections	8	0.0010%	0.033	0.000003	0	0.000003	0.00001
Total HAPs						0.0001	0.001

<u>Fugitve HCl Emissions factor basis.</u>

Note 1 - HCl emissions are based on conservative assumption of 10 ppmv HCl in syngas per vendor.

Other Metals (see below)

Fugitive Source	Component Count	Total Metalic HAP Conc.	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	270	0.000004%	0.0089	0.0000001	0	0.0000001	0.0000004
Flanges	650	0.000004%	0.0029	0.0000001	0	0.0000001	0.0000003
Compressor Seals	0	0.000004%	0.5027	0	0	0	0
Pump Seals	0	0.000004%	0.0386	0	0	0	0
Relief Valves	36	0.000004%	0.2293	0.0000003	0	0.0000003	0.000001
Sample Connections	8	0.000004%	0.033	0.00000001	0	0.00000001	0.00000005
Total HAPs						0.000001	0.000002

See next page for metalic hap

Control Efficiencies shown above of zero reflect the fact that the syngas piping is not subject to any control requirements (i.e.; LDAR is not required.)

Metal HAPs factors for Fugitives leaks of Syngas

HAP	Factor		Basis of Factor
Arsenic[2]	0.0000001%	volume %	Note 2
Beryllium[2]	0.0000001%	volume %	Note 2
Cadmium[2]	0.00000001%	volume %	Note 2
Chromium[2]	0.0000001%	volume %	Note 2
Cobalt[2]	0.00000001%	volume %	Note 2
Manganese[2]	0.0000001%	volume %	Note 2
Mercury[3]	0.000004%	volume %	Note 3
Nickel[2]	0.0000001%	volume %	Note 2
Selenium[2]	0.0000001%	volume %	Note 2
Lead[2]	0.0000001%	volume %	Note 2
Total HAPs for Syngas combustion	**0.000004%**	**volume %**	

<u>Fugitve Metal HAPs Emissions factor basis.</u>

Note 2 - Metal HAP factors (except mercury) are from Proposed Duke Edwardsport

Note 3 - Mercury content of syngas is .0352 ppmv per engineering estimate.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD)
Appendix B – Public Comments List

Source Description and Location

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Permit Reviewer:	**Josiah Balogun**

Public Commenters

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

Alec Kalla	8733 West Summit Circle Drive, French Lick, IN 47432
Don Schroeder	2281 W. Co. Road 350S, Rockport IN 47635
David L. Boggs	216 Western Hills Drive, Mount Vernon, IN 47620
John Blair	Valley Watch, Inc 800 Adams Avenue, Evansville IN 47713
Ben A. Taylor	419 Yelvington - Grandview Rd, Maceo, KY 42355
Meleah Geertsma	1152 15th Street, NW, Suite 300 Washington, DC 20005
George Peridas	111 Sutter St. 20th Floor, San Francisco, CA 94104
Robert Ukeiley	435R Chestnut Street, Suite 1 Berea KY 40403
John Thompson	Clean Air Task Force, 18 Tremont St., Suite 530 Boston MA 02108
Greg Sitzman	410 Seminary St, Rockport, IN 47635
Richard Michel	2222E County Rd. 700N, Grandview, IN 47615
Kathy Ferguson	Rockport
Evelyn Godwin	
Rex Windchill	
Cara Beth Jones	
Greg James	
William Rosenberg	

Speakers Present at the Public Hearing and Public Meeting held on Wednesday, January 25, 2011 at South Spencer High School, Auditorium, 1141 North Orchard Road, Rockport Indiana.

Bowden Quinn
Wayne Werne
Rock Blanchard
Angela Vanover
Marvin Byrer
James Lacy Kamuf
Mickey Toler
Dan Rininger
Tom Utter
Harold Goffinet
Greg James
Rex Winchell
Ferman Yearby
Chuck Botsko
John Blair
Jean Dolezal
N. Ryan Zaricki
Wallace McMullen
Ben Taylor
Thomas Pearce
William Rosenberg
Ryan Hidalgo
Steve Sisley
Steve McNamara
Larry Herm
Rick Mckee

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a New Source Construction and Part 70 Permit

Source Description and Location

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

The Office of Air Quality (OAQ) has reviewed a New Source Construction and Part 70 operating permit application submitted by Indiana Gasification LLC, on April 20, 2011, in relating to the construction and operation of a state - of- the - art substitute natural gas ("SNG") and liquefied carbon dioxide ("CO2") production plant.

History

The proposed facility is designed to convert Illinois Basin coal and petroleum coke into pipeline-quality SNG and liquefied CO_2. The project will produce up to 48 billion standard cubic feet (Bscf) of SNG annually utilizing approximately 3.5 million tons of feedstock. About 39 Bscf will be sold to the Indiana Finance Authority (“IFA”) for use by Indiana natural gas consumers with the remaining sold in the natural gas marketplace. The project will also produce annually up to approximately 6.43 million tons of liquefied CO_2 that will be sold to third parties for use in Enhanced Oil Recovery (“EOR”) where it is estimated to produce approximately 10,000,000 barrels per year of additional domestic oil in the Gulf Coast region.

Facility development is supported by an agreement with the IFA regarding the purchase of the SNG production and a loan guarantee currently being negotiated with the Department of Energy, which is intended to encourage advanced coal gasification facilities. As a result, the project must conform to any provisions in contracts relating to these agreements.

The facility will have several products in addition to SNG and liquefied CO_2. Sulfur compounds in the feedstocks will be processed into sulfuric acid, which IG plans to sell into the industrial market. Argon will be recovered from the air separation unit and sold to one or more industrial gas companies. Heat generated during the gasification process will be used to produce steam for steam turbines that can produce approximately 300 MW, primarily to meet on-site power needs. Depending on process and ambient conditions, a small amount of power will be exported into or imported from the nearby electrical transmission system.

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in Spencer County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
$PM_{2.5}$	Attainment effective November 2, 2011, for the annual PM2.5 standard for the Evansville area, including Ohio Township of Spencer County.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005.	

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

(b) $PM_{2.5}$
Spencer County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, November 2, 2011. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

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

Fugitive Emissions

Since this source is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Description of New Source and Emission Units with Control Equipment Summary

The Office of Air Quality (OAQ) has reviewed a New Source Construction application, submitted by Indiana Gasification, LLC on April 20, 2011, relating to the construction and operation of a state - of- the - art substitute natural gas ("SNG") and liquefied carbon dioxide ("CO_2") production plant. The proposed facility is designed to convert Illinois Basin coal and petroleum coke into pipeline-quality SNG and liquefied CO_2. The project will produce up to 48 billion standard cubic feet (Bscf) of SNG annually utilizing approximately 3.5 million tons of feedstock. The project will also produce annually approximately 4.9 million tons of liquefied CO_2 that will be sold to third parties for use in Enhanced Oil Recovery ("EOR") where it is estimated to produce approximately 10,000,000 barrels per year of additional domestic oil in the Gulf Coast region. The following is a list of the proposed emission unit(s) and pollution control device(s):

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

  (1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

  (2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

    (a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

    (b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

    (c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

    (d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

    (e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

    (f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

    (g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

    (h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, to be permitted in 2012, exhausting through one (1) tip, identified as S-001.

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, to be permitted in 2012, exhausting through one (1) tip, identified as S-002.

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, to be permitted in 2012, with methanol, H_2S, COS, and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, to be permitted in 2012, with NO_x, SO_2, H_2SO_4 emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, exhausting through two (2) stacks, identified as

S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected sources.]

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, to be permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

(I) One (1) ZLD-Spray Dryer, to be permitted in 2012, nominally rated at 5.6 MMBtu/hr with PM emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

(K) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.

(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6) identified as emissions unit FUG-SF6, to be permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA and methanation are identified as emissions units FUG and FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

(N) One (1) ZLD Inert Gas Vent identified as EU-033, to be permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

Insignificant and Trivial Activities

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

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

(c) Four (4) rod mill eductor vent stacks, to be permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(d) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(e) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

(f) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vents, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, to be permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

(g) One (1) slag handling storage pad, to be permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(h) One (1) front-end loader activity on the slag storage pad, to be permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

(i) One (1) fixed roof recycle solid tank, to be permitted in 2012, with a nominal capacity of 14,400 gallons, identified as EU-019.

(j) Five (5) fixed roof slurry run tanks, each, to be permitted in 2012, with a nominal capacity of 47,700 gallons, identified as EU-020A through EU-020E.

(k) Two (2) fixed roof grey water tanks, to be permitted in 2012, each with a nominal capacity of 88,000 gallons, identified as EU-021A and EU-021B.

(l) One (1) fixed roof slurry additive tank, to be permitted in 2012, with a nominal capacity of 28,500 gallons, identified as EU-022.

(m) Five (5) open slag sumps, to be permitted in 2012, each with a nominal capacity of 15,600 gallons, identified as EU-023A through EU-023E.

(n) One (1) pressurized Sour Water Stripper Surge Tank, to be permitted in 2012, with a nominal capacity of 175,000 gallons, identified as EU-026.

(o) Six (6) fixed roof sulfuric acid storage tanks, to be permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

(p) Two (2) fixed roof aqueous ammonia storage tanks, to be permitted in 2012, each with a nominal capacity of 31,000 gallons - identified as EU-028A and EU-028B, with ammonia emissions controlled with two (2) water scrubbers identified as C-028A and C-028B, respectively.

(q) One (1) fixed roof Diesel Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 9,240 gallons, identified as EU-029.

(r) One (1) fixed roof Gasoline Fuel Storage Tank, to be permitted in 2012, with a nominal capacity of 1,030 gallons, identified as EU-030.

(s) One (1) fixed roof triethylene glycol storage tank, to be permitted in 2012, with a nominal capacity of less than 10,000 gallons, identified as EU-031.

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

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

Unrestricted Potential Emissions – Part 70

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

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

PTE Before Controls	
Pollutant	**Potential To Emit (ton/yr)**
PM	322.93
PM_{10}	207.09
$PM_{2.5}$	73.63
SO_2	119.9
VOC	90.26
CO	302,916
NO_X	588.4
H_2SO_4	43.89
H_2S	12.3
Pb	0.04
Hg	0.07
GHGs as CO_2e	3,094,536 (Note 1)

HAPs	Potential To Emit (tons/year)
Methanol	17.98
Lead	0.04
Beryllium	0.000059
Mercury	0.07
Manganese	< 10
Chlorine	< 10

HAPs	Potential To Emit (tons/year)
Formaldehyde	< 10
other HAPs	greater than 10
Total HAPs	greater than 25

Note 1: The above GHG emissions reflect the PTE in operating Year 3 and beyond. The PTE Year 1 estimated as 6,494,536 tons/yr CO2e. The PTE Year 2 estimated as 8,234,536 tons/yr CO2e.

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, $PM_{2.5}$, SO_2, CO and NOx are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of all other regulated pollutants are less than 100 tons per year.

(d) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

Actual Emissions

No previous emission data has been received from the source.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

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

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units at Indiana Gasification, LLC. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (ton/yr)													
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NOx**	**H_2SO_4**	**H_2S**	**Pb**	**Hg**	**Metha-nol**	**Total HAPs**	**Total GHG CO_2e**
Syngas Hydrocarbon Flare-001	0.44	0.44	0.41	1.97	0.03	23.5	6.07	0	0.04	3E-06	1.9E-06	0	0	13,343
Acid Gas Flare - 002	0.01	0.01	0.01	0.001	0.023	0.06	0.23	0	0	3E-06	1.9E-06	0	0	136
Auxiliary Boiler (A-B) -005	5.62	5.62	5.62	0.44	4.07	27.15	9.43	0	0	2E-03	1.3E-03	0	1.4	88,254
Acid Gas Recovery Unit (A-B) -007	2.46	2.46	2.46	26.98	8.96	410.27	16.85	0	0.1	9.6E-0.4	5.5E-04	9.0	22.5	1,290,000
Gasifier Preheat Burners (A-E) -008	0.04	0.04	0.04	0.03	0.3	3.08	5.51	0	0	1.6E-04	9.0E-05	0	0.1	6444
Emergency Diesel Generators (A-B) -009	0.003	0.003	3E-04	0.008	0.015	0.019	0.76	0	0	0	0	0	0	84
Emergency Firewater pumps (A-C) - 010	0.008	0.008	8E-03	5E-04	0.017	0.06	0.24	0	0	0	0	0	0	
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011	3.8	3.8	1.86	0	0	0	0	0	0	1.1E-03	5.5E-06	0	0	0
Incoming Solid Feed stock handling (Coal/petcoke) (A-	5.45	3.25	0.88	0	0	0	0	0	0	0	8.9E-06	0	0	0

	Potential to Emit (ton/yr)													
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NOx**	**H_2SO_4**	**H_2S**	**Pb**	**Hg**	**Metha-nol**	**Total HAPs**	**Total GHG CO_2e**
AC) - 012														
Rod Mill (A-D) -013	0.44	0.44	0.13	0	0	0	0	0	0	0	3.8E-07	0	0	0
Wet Sulfuric Acid Plant (A-B) - 015	42.6	42.6	42.6	70.74	0.01	159.7	86.93	42.6	0	6E-06	3.5E-06	0	0	474,000
Cooling Tower - ASU - 016A	0.9	0.9	0.70	0	0	0	0	0	0	0	0	0	0	0
Cooling Tower - Main - 016B	6.65	6.65	5.19	0	0	0	0	0	0	0	0	0	0	0
ASU Molecular Sieve Regeneration (A-B) - 017	0.22	0.22	0.08	0	0	0	0	0	0	0	0	0	0	0
Slag Sump (A-E) - 023	0	0	0	0	0	0	0	0	0.1	0	0	0	0	0
Methanol Deinventory Tank - 024	0	0	0	0	0.16	0	0	0	0	0	0	0.16	0.16	0
Fresh Methanol Storage Tank - 025	0	0	0	0	0.13	0	0	0	0	0	0	0.13	0.13	0
Sour Water Striper Surge Tank - 026	0	0	0	0	0.004	0	0	0	0.54	0	0	0	0	0
Sulfuric Acid Storage Tank (A-F) - 027	0.0015	0.0015	0.0015	0	0	0	0	0.0015	0	0	0	0	0	0
Diesel Fuel Storage Tank - 029	0	0	0	0	0.35	0	0	0	0	0	0	0	0.07	0
Gasoline Fuel Storage Tank - 030	0	0	0	0	0.1	0	0	0	0	0	0	0	0	0

	Potential to Emit (ton/yr)													
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NOx**	**H_2SO_4**	**H_2S**	**Pb**	**Hg**	**Metha-nol**	**Total HAPs**	**Total GHG CO_2e**
Triethylene Glycol Storage Tank - 031	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ZLD Spray Dryer - 032	0.51	0.51	0.48	0.015	0.13	0.89	0.86	0	0	7E-05	4.1E-05	0	0.046	2886
ZLD Inert Gas Vent (033)	0	0	0	0	0	0	0	0	0	0	3.6E-04	0	0	203.7
EU-034A and EU-034C	0.04	0.017	0.0024	0	0	0	0	0	0	0	0	0	0	0
Fugitive Emissions														
Gasification, Shift Conv., AGR, Methanation - FUG	0	0	0	0	1.61	9.45	0	0	0.37	0	0	0.37	0.38	21
WSA - FUG-WSA	0	0	0	0.003	0	0	0	009	3.74	0	0	0	0	4
Plant Haul Road - FUG ROAD	0.45	0.09	0.022	0	0	0	0	0	0	0	0	0	0	0
Electric Circuit Breakers - FUG SF6	0	0	0	0	0	0	0	0	0	0	0	0	0	72
Total Emission for New Source Construction	**69.63**	**67.05**	**60.48**	**100.2**	**15.90**	**634.18**	**126.9**	**42.68**	**4.89**	**0.004**	**0.0023**	**9.66**	**24.79**	**1,875,448** **(Note 2)**
Nonattainment NSR Major Source Thresholds	**--**	**--**	**100**	**100**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**
Significant Level	**25**	**15**	**10**	**40**	**40**	**100**	**40**	**7**	**10**	**0.6**	**0.1**	**10**	**25**	**75,000**

Note 2: The above GHG emissions reflect the PTE in operating year three and beyond. The PTE Year 1 estimated as 5,275,448 tons/yr CO2e. The PTE Year 2 estimated as 7,015,448 tons/yr CO2e.

This new stationary 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, emissions of GHGs are equal to or greater than one hundred thousand (>100,000) tons of CO_2 equivalent emissions (CO_2e) per year, which is greater than the PSD threshold and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(gg)(1). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do apply to the new source.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this New Source Construction:

(a) 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 Part 70 major source threshold for the pollutant involved;

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

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

CAM Applicability Analysis

Emission Unit	**Control Device Used**	**Emission Limitation** (Y/N)	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable** (Y/N)	**Large Unit** (Y/N)
Syngas Hydrocarbon Flare -001 (CO)	N	Y	> 100	< 100	100	N	N
Auxiliary Boiler - 005 (CO)	N	Y	> 100	< 100	100	N	N
Acid Gas Recovery Unit (A-B) -007 (CO)	Y	Y	> 100	> 100	100	Y	Y
Wet Sulfuric Acid Plant (A-B) - 015 (NOx)	Y	Y	>100	< 100	100	Y	N
Wet Sulfuric Acid Plant (A-B) - 015 (SO_2)	Y	Y	>100	< 100	100	Y	N
Wet Sulfuric Acid Plant (A-B) - 015 (H_2SO_4)	Y	Y	> 100	< 100	100	Y	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to Wet Sulfuric Acid Plant (A-B) - 015 for NOx, SO_2 and H_2SO_4, the Acid Gas Recovery Unit (A-B) -007 for CO, upon start-up. A CAM plan has been submitted (See Appendix D for the detailed CAM Plan).

CAM does not apply to any other emission units at this source, either because their uncontrolled emissions rate is less than 100 tpy or because emissions are limited by inherent process equipment that is not considered a control device per the 40 CFR 64.1 definition of inherent process equipment.

(b) The requirements of Area Source MACT- National Emission Standards for Hazardous Air Pollutants – Industrial, Commercial, and Institutional Boilers at Area Sources 40 CFR Part 63 Subpart JJJJJJ recently promulgated for Industrial, Commercial, and Institutional Boilers (Area Boiler MACT) do not apply to the auxiliary boiler, identified as (E005). The final EPA rule does not regulate area source boilers that fire only natural gas fuel – because they do not emit sufficient urban air toxics to require regulation. In the proposed rule preamble, EPA states*: " . . . pursuant to section 112(c)(3) of the CAA, we are proposing emission standards for the above mentioned HAP for area source boilers fired by coal, oil, and wood, but not standards for boilers fired by natural gas*." In the final rule Preamble EPA again clarified that *"Notably, gas-fired units are not included in the source category listing for area source boilers."*

(c) The requirements of Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971 40 CFR 60, Subpart D are not applicable to any sources in this project. The requirements of this rule apply to steam-generating units that commence construction, modification, or reconstruction after August 17, 1971 and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 73 MW (250 million Btu/hour). Although the auxiliary boilers (EU 005A/B) have a heat input capacity greater than 250 MMBtu/hr, each and are steam-generating units, pursuant to 40 CFR 60.40b(j) the auxiliary boilers are exempt from the requirements of NSPS Subpart D because they are instead subject to the requirements of NSPS Subpart Db.

The thermal oxidizers (EUs 007A, B) and the gasifier pre-heat burners (EUs 008A-E) have a maximum design heat input capacity less than 73 MW (250 MMBtu/hr) and they are not steam-generating units; therefore Subpart D does not apply to these sources.

(d) The requirements of Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978 40 CFR 60, Subpart Da do not apply to any emission units at the sources. The requirements of this rule apply to electric utility steam-generating units that commence construction, modification, or reconstruction after September 18, 1978, and that have a heat input capacity from fuels combusted in the steam-generating unit of greater than 73 MW (250 million Btu/hour). The auxiliary boilers, which can supply steam to an electric generating steam turbine are steam-generating units, but they are not considered electric utility units because they will not supply more than 1/3 of its potential electrical output capacity to any utility power distribution system.

The requirements of this rule 40 CFR 60, Subpart Da are not applicable to the thermal oxidizers (EUs 007A, B) or gasifier pre-heat burners (EUs 008A-E) since they do not meet the definition of an electric utility steam generating unit. Specifically, the thermal oxidizers and the pre-heat burners do not generate steam, and thus are not steam generating units.

(e) The requirements of Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units 40 CFR 60, Subpart Dc are not applicable to any of the emission units at source. The requirements of this rule are applicable to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). The auxiliary boilers (EU 005A/B) have a heat input capacity greater 100 MMBtu/hr; therefore Subpart Dc does not apply. The thermal oxidizers (EUs 007A, B) and the burners (EUs 008A-E) are not steam generating units; therefore, 40 CFR 60, Subpart Dc does not apply.

(f) **40 CFR Part 63 Subpart VVVVVV—National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources** While this facility is an area source of HAPs, This source is not subject to 40 CFR Part 63 Subpart VVVVVV because this rule only regulates facilities that use as feedstocks, generates as byproducts, or produces as products any of the hazardous air pollutants (HAP) listed in Table 1 to this subpart. This facility does not use any of the listed HAPs as a feedstock or generate them as products or byproducts.

(g) 40 CFR 60 Subparts VVa, III, NNN, RRR and YYY –Standards of Performance that apply to the Synthetic Organic Chemicals Manufacturing Industry. This facility does not manufacturer any of the SOCMI chemicals listed in 40 CFR 60.489

(h) 40 CFR 60 Subparts J,GGGa, and QQQ – Standards of Performance that apply to petroleum refineries. This facility does not process petroleum and therefore does not meet the definition of petroleum refinery under these standards.

(i) 40 CFR 60 Subparts KKK and LLL – Standards of Performance that apply to natural gas processing facilities. These rules apply to facilities that extract and process natural gas liquids from field gas. This facility does not meet the definition of a natural gas processing facility under these two rules.

(j) The requirements of Standards of Performance for Sulfuric Acid Plants 40 CFR 60, Subpart H do not apply to the project's Sulfuric Acid Plant, because it does not meet the rule's definition of a sulfuric acid production unit. 40 CFR 60, Subpart H applies to sulfuric acid plants defined as follows (emphasis added):

> *(1) Sulfuric acid production unit means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.*

The Indiana Gasification, LLC Sulfuric Acid Plant is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfuric compounds. Therefore, it does not fit the applicability requirement shown above. The sulfuric acid facility is a sulfur recovery process which converts the sulfur compounds removed from the syngas in the AGR, thereby preventing their emissions to the atmosphere. The H_2S and COS in the acid gas stream from the Rectisol Process is combusted for conversion to SO_2. The SO_2 rich gas produced is sent to catalyst beds for conversion to SO_3 and then conversion to sulfuric acid (H_2SO_4) after reaction with water.

Therefore, the Indiana Gasification sulfuric acid plant does not meet the definition of sulfuric acid production unit as defined by 40 CFR 60, Subpart H and does not apply to the WSA stack vents (EUs 015A, B). This is further confirmed by an EPA applicability determination for an analogous sulfuric acid plant at a petroleum refinery. In this 1995 applicability memo (ADI control number 9600093), EPA states that a WSA that produces H_2SO_4 from H_2S is not covered by NSPS Subpart H.

(k) The requirements of Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 40 CFR 60, Subpart Kb are not applicable to the following storage tanks listed below because the tanks do not store organic materials and have capacities and maximum true vapor pressure less than 151 cubic meters (m^3) and 3.5 kPa, respectively.

EU No.	Tank ID	Tank Capacity (Gal)	Max. Vapor Pressure Psia	40 CFR 60, Subpart Kb	Tank Vents to:
023 A	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 B	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 C	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 D	Slag Sump	25,284	1.52	No (1)	Atmosphere
023 E	Slag Sump	25,284	1.52	No (1)	Atmosphere

EU No.	Tank ID	Tank Capacity (Gal)	Max. Vapor Pressure Psia	40 CFR 60, Subpart Kb	Tank Vents to:
027 A	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 B	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 C	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 D	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 E	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
027 F	Sulfuric Acid Storage Tank	867,000	<0.5	No (1)	Atmosphere
028 A	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
028 B	Aqueous Ammonia Tank	32,243	5.38	No (1)	Atmosphere
030	Gasoline Tank	1,175	6.20	No (2)	Atmosphere

Note: (1) Tank does not store VOCs.
(2) This source is not subject to NSPS Subpart Kb because the tank does not meet the capacity criteria.

(l) The auxiliary boilers, identified as EU 005A and EU-5B are subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for Industrial -Commercial Institutional Steam Generating Unit, which is incorporated by reference as 326 IAC 12 because they are boilers that will commence construction, modification, or reconstruction after June 19, 1984, and that have 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)). The auxiliary boilers, identified as EU 005A and EU- 5B, each has a heat input capacity greater than 100 MMBtu/hr. The specific facilities subject to this rule includes the following.

(1) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected source.]

The boilers are subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b(a);
(2) 40 CFR 60.40b(j);
(3) 40 CFR 60.41b(b);
(4) 40 CFR 60.42b(k)(2);
(5) 40 CFR 60.44b(h);
(6) 40 CFR 60.44b(i);
(7) 40 CFR 60.44b(l);
(8) 40 CFR 60.46b(a);
(9) 40 CFR 60.46b(c);
(10) 40 CFR 60.46b(e)(1);
(11) 40 CFR 60.46b(e)(3);
(12) 40 CFR 60.48b(b);
(13) 40 CFR 60.48b(c);
(14) 40 CFR 60.48b(d);
(15) 40 CFR 60.48b(e)(2);
(16) 40 CFR 60.48b(e)(3);
(17) 40 CFR 60.48b(f);

(18) 40 CFR 60.49b(a);
(19) 40 CFR 60.49b(b);
(20) 40 CFR 60.49b(d);
(21) 40 CFR 60.49b(g);
(22) 40 CFR 60.49b(i); and
(23) 40 CFR 60.49b(o).

NOTE: The auxiliary boilers will only fire natural gas or SNG. Therefore, Subpart Db will not impose any applicable PM_{10} or SO_2 emission standards. The Subpart Db NO_x standard applicable to these sources, high heat release boilers, is 0.10 lb/MMBtu (per 40 CFR 60.44b (a) (1) (ii)). This emission limit is less restrictive than the proposed Best Available Control Technology (BACT) limit discussed in Section 5. NO_x emission will be controlled with the use of ultra low NO_x burners and flue gas recirculation.

Compliance testing will be performed per 40 CFR 60.46b(e). NOx monitoring will be accomplished using a continuous emission monitoring system (CEMS) per 40 CFR 60.48b(b)(1).

(m) The requirements of Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 40 CFR 60, Subpart Kb are applicable to the Methanol Deinventory Tank, Identified as 024 and the fresh Methanol Storage Tank, identified as 025 because they store organic materials, will have commenced construction after July 23, 1984, have capacities greater than 151 cubic meters (m^3) (39,889 gallons) and store only volatile organic compounds with a maximum true vapor pressure greater than 3.5 kPa. The specific facilities subject to this rule includes the following.

(A) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb].

The storage tanks are subject to the following portions of Subpart Kb:

(1) 40 CFR 60.110b(a);
(2) 40 CFR 60.110b(e);
(3) 40 CFR 60.111b;
(4) 40 CFR 60.112b(a)(3);
(5) 40 CFR 60.112b(a)(4);
(6) 40 CFR 60.113b(c);
(7) 40 CFR 60.114b(c);
(8) 40 CFR 60.115b(c);
(9) 40 CFR 60.116b(a);
(10) 40 CFR 60.116b(b);
(11) 40 CFR 60.116b(e); and
(12) 40 CFR 60.116b(g).

(n) The source is subject to the New Source Performance Standard - Standards of Performance for Coal Preparation and Processing Plants, 40 CFR 60, Subpart Y, which is incorporated by reference as 326 IAC 12. These requirements apply to facilities that prepare coal by one of more of several listed processes and which process more than 161 mega-grams per day (200 tons per day) of coal and commenced construction after May 27, 2009. The activities regulated by this NSPS include crushing, screening, conveying, and transferring of coal. The specific facilities subject to this rule include the following.

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

(1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

(2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

   (a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

   (b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

   (c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

   (d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

   (e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

   (f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

   (g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively;

   (h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

   (i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 31,870 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

The source is subject to the following portions of Subpart Y.

(1) 40 CFR 60.250(a);
(2) 40 CFR 60.250(d);
(3) 40 CFR 60.251;
(4) 40 CFR 60.254(b);
(4) 40 CFR 60.254(c);
(5) 40 CFR 60.255(b);
(6) 40 CFR 60.255(c);
(7) 40 CFR 60.255(d);
(8) 40 CFR 60.255(e);
(9) 40 CFR 60.255(f);
(10) 40 CFR 60.255(g);
(11) 40 CFR 60.255(h);
(12) 40 CFR 60.256(b)(1);
(13) 40 CFR 60.256(b)(3);
(14) 40 CFR 60.256(c);
(15) 40 CFR 60.257(a);
(16) 40 CFR 60.258(a)(1);

(17) 40 CFR 60.258(a)(2);
(18) 40 CFR 60.258(a)(3);
(19) 40 CFR 60.258(a)(4);
(20) 40 CFR 60.258(a)(5);
(21) 40 CFR 60.258(a)(6);
(22) 40 CFR 60.258(a)(7);
(23) 40 CFR 60.258(a)(8);
(24) 40 CFR 60.258(a)(10);
(25) 40 CFR 60.258(b)(2);
(26) 40 CFR 60.258(b)(3);
(27) 40 CFR 60.258(c); and
(28) 40 CFR 60.258(d).

(o) The source is subject to the requirements of 40 CFR, Subpart IIII - Standard of Performance for Stationary Compression Ignition Internal Combustion Engines because the emergency generators and the firewater diesel pump will be constructed after July 11, 2005 and manufactured after April 1, 2006. The specific facilities subject to this rule includes the following.

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

The emergency generator and the firewater pumps are subject to the following sections of 40 CFR Part 60, Subpart IIII.

(1) 40 CFR 60.4200(a);
(2) 40 CFR 60.4205(b);
(3) 40 CFR 60.4205(c);
(4) 40 CFR 60.4206;
(5) 40 CFR 60.4207(a);
(6) 40 CFR 60.4207(b);
(7) 40 CFR 60.4208(a);
(8) 40 CFR 60.4208(b);
(9) 40 CFR 60.4208(g);
(10) 40 CFR 60.4209(a);
(11) 40 CFR 60.4211(a);
(12) 40 CFR 60.4211(c);
(13) 40 CFR 60.4211(e);
(14) 40 CFR 60.4212(a);
(15) 40 CFR 60.4212(b);
(16) 40 CFR 60.4212(c);
(17) 40 CFR 60.4214(b);
(18) 40 CFR 60.4218;
(19) 40 CFR 60.4219;
(20) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines;
(21) Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines;

(22) Table 6 to Subpart IIII of Part 60 - Optional 3-Mode Test Cycle for Stationary Fire Pump Engines; and
(23) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart III.

(p) The source is subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63 Subpart ZZZZ). These Standards apply to new stationary reciprocating internal combusting engines (RICE) and are located at facilities that are area source of HAPs. The specific facilities subject to this rule include the following.

These emissiosn units are subject to the following portions of Subpart ZZZZ:

(a) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

(b) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, emergency diesel fired generator is considered a new affected source.].

The emergency generator and the firewater pumps are subject to the following sections of 40 CFR Part 63, Subpart ZZZZ.

(1) 40 CFR 63.6590(c)(1).

Pursuant to 40 CFR 63.6665, the two (2) emergency diesel generators and the three (3) firewater pump diesel engines do not have to meet the requirements of 40 CRF 63, Subpart A (General Provisions), since they are considered new stationary RICE located at an area source of HAP emissions.

(q) The source is not a major source of HAPs and is not subject to any of the major source MACT standards under 40 CFR Part 63. However, in the context of the BACT determination for this source, the substantive requirements of 40 CFR 63 Subpart H, addressing equipment leaks, apply to the components listed under 40 CFR 63.160(a) that are in service at the facility for the following process streams: methanol streams, propylene streams, and product SNG streams. The same Subpart H requirements apply to any leaks of SO2 in the Wet Sulfuric Acid unit piping between the combustor and oxidation reactor, beginning with the connector at the combustor and ending with the connector at the oxidation reactor, except that references in the regulations to methane or VOCs will instead be applied to the pollutant SO2.

The following standards will apply to the components subject to this permit requirement:

1. 40 CFR 63.161;
2. 40 CFR 63.162(a);
3. 40 CFR 63.162(c);
4. 40 CFR 63.162(d);
5. 40 CFR 63.162(f);
6. 40 CFR 63.162(g);
7. 40 CFR 63.162(h);
8. 40 CFR 63.163;
9. 40 CFR 63.164;

10. 40 CFR 63.165;
11. 40 CFR 63.166;
12. 40 CFR 63.167;
13. 40 CFR 63.168;
14. 40 CFR 63.169;
15. 40 CFR 63.170;
16. 40 CFR 63.171;
17. 40 CFR 63.172;
18. 40 CFR 63.173; and
19. 40 CFR 63.174.

The alternative quality improvement program for valves under 40 CFR 63.175 and pumps under 40 CFR 63.176 may be used in lieu of the specified requirements of 40 CFR 63.168 and 40 CFR 63.163. The source may apply any alternative method approved by the EPA Administrator under 40 CFR 63.177(e) with written notification to IDEM 30 days in advance of the use of the alternative method. That notification shall include a copy of the EPA approval of the alternative method and an indication of where at the plant the alternative will be applied.

The test methods and procedures used shall be those delineated under 40 CFR 63.180. For the SO2 monitoring of the components in the Wet Sulfuric Acid (WSA), references to methane or VOCs in 40 CFR 63.180 or 40 CFR 60 Appendix A, Method 21 shall be applied instead to the pollutant SO2. If a monitor is used that has a range lower than the defined leak rate, then any reading within 90% of the monitor's range shall be treated as a leak.

The Greenhouse Gases BACT determination for this source, shall be to monitor monthly seals of the CO2 product compressors using audio/visual methods. Any leakage determined by audio/visual or other inspection shall be repaired within the time frames specified in 40 CFR 63.164 (g) except as provided by 63.171 and Recordkeeping shall conform to the provisions of 40 CFR 63.181.

(r) **326 IAC 24 Clean Air Interstate Rule (CAIR)**

The Clean Air Interstate Rule (CAIR) is not applicable to any source at the IG facility. CAIR applies to fossil-fuel fired boilers serving a generator with a nameplate capacity of more than 25 MW and producing electricity for sale. The Auxiliary Boilers (EU-05A/B) are fossil-fuel fired boilers serving a generator. However, pursuant to 326 IAC 24-1(b)(1)(B) the CAIR does not apply to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale. Electricity produced by the Indiana Gasification facility is intended to balance the energy requirements of the facility. This electricity will normally be produced from process generated steam in a steam turbine generator, and any excess that is distributed for sale will not exceed 1/3 of the potential generation. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 24.

(s) **40 CFR Part 72-78 Acid Rain Program**

326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is not subject to the requirements of 326 IAC 21 because it does not sell greater than 1/3 its generated electric. This regulation applies to electric utility generating units that supply greater than 1/3 their potential electrical output and greater than 219,000 MWe-hrs (25MW) actual electrical output on an annual basis to any utility power distribution system for sale. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 21.

(t) **40 CFR 68 Chemical Accident Prevention Provisions**
Chemical accident prevention provisions (Risk Management Plans - RMP) are applicable to the stationary sources that have more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115. Compounds present on site which are RMP regulated pollutants includes ammonia, methane and hydrogen sulfide. However, none are present in concentrations or total quantities which trigger RMP applicability. Indiana Gasification, LLC will use aqueous ammonia, however its concentration is less than 20% ammonia – and is therefore is not hazardous enough to be regulated per RMP regulations. Methane, the major product of the facility, is not present in any process greater than the RMP threshold quantity of 10,000 lbs. Hydrogen sulfide will be present in the process, but is present in most processes in concentrations less than 1% (H_2S is not RMP regulated below this concentration.) The total quantity of H2S in processes where it is present less than 1.0% concentration is below the RMP threshold quantity of 10,000 lbs.

State Rule Applicability Determination

326 IAC 2-2 (Prevention of Significant Deterioration)
This new stationary source is one of the 28 listed source categories and has potential to emit of at least one regulated pollutant greater than 100 tons per year. This source is a major source pursuant to 326 IAC 2-2 (PSD).

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T147-30464-00060 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the source shall be as follows:

Syngas Hydrocarbon Flare, identified as (EU-001):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce PM, PM10 and PM2.5 emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

b. Flares shall be operated with a flame present at all times.

c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare PM/PM_{10} emissions shall not exceed 3.21 lb/hour during startup or shutdown, based on a 3-hour average.

D. The Syngas Hydrocarbon Flare $PM_{2.5}$ emissions shall not exceed 3.01 lb/hour during startup or shutdown, based on a 3-hour average.

(2) The CO emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce CO emissions during startups, shutdowns and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The Permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:
a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

C. The Syngas Hydrocarbon Flare CO emissions shall not exceed 172.4 lb/hour during startup or shutdown based on a 3 hour average.

(3) The SO_2 emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce SO2 emissions during startups, shutdowns, and other flaring events.

The permittee will use methanol, rather than coal or pet coke, as the feedstock in each gasifier during startup conditions requiring syngas flaring, thereby reducing emissions of sulfur dioxide at the syngas hydrocarbon flare.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented

The SO2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lb per 24 hours. The SO2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3 hour average.

(4) The NOx emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce NOx emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. The Syngas Hydrocarbon Flare NOx emissions shall not exceed 43.09 lb/hour during startup or shutdown based on a 3 hour average.

(5) The GHGs emissions from the Syngas Hydrocarbon Flare, identified as (EU-001) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce GHG emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Acid Gas Flare, identified as (EU-002):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B. Comply with the following flare best practices:

a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flare with a thermocouple, infrared monitor, or other approved device.

(2) The CO emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

B Comply with the following flare best practices:
a. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
b. Flares shall be operated with a flame present at all times.
c. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(3) The SO_2 emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(4) The NOx emissions from the Acid Gas Flare, identified as (EU-002) shall be limited as follows:

B. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(5) The GHG emissions from the Acid Gas Flare, identified as (EU-002) shall be:

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Auxiliary Boilers, identified as (EU-005 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0075 lb per MMBtu and only natural gas or SNG shall be used.

(2) The CO emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.036 lb/MMBtu based on a 3 - hour average and good combustion practices shall be used.

(3) The SO_2 emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0006 lb/MMBtu and only natural gas or SNG shall be used.

(4) The NOx emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0125 lb/MMBtu based on a 24-hour block daily average basis and shall use Ultra Low NOx burners with FGR.

(5) The GHGs BACT for the Auxiliary Boilers shall be as follows:

(a) Use of natural gas or SNG;

(b) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)

(c) Boiler designed for 81% thermal efficiency (HHV).

(d) The total CO_2 emissions from the auxiliary boilers shall not exceed 88,167 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Acid Gas Recovery Unit Vents, identified as (EU-007 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from operation of the AGR Regenerative Thermal Oxidizers (C-007A/B) shall not exceed 0.29 pounds per hour, each and shall use good combustion practices. Only natural gas or SNG shall be used in the AGR Regenerative Thermal Oxidizers (C-007A/B).

(2) The CO emissions shall be controlled by the use of regenerative thermal oxidizer (RTO) and the CO emissions shall not exceed 48 pounds per hour for the Acid Gas Removal Unit Vents (EU-007A/B), each, based on a 3-hour average.

(3) The SO_2 emissions shall be reduced by the use of a Rectisol process and the SO_2 emissions shall not exceed 3.17 pounds per hour for each Acid Gas Removal Unit Vent (EU-007A/B), based on a 3-hour average.

(4) The NOx emissions from the Acid Gas Removal Unit Vents (EU-007A/B) shall be controlled by Low NOx Performance with natural gas injection and the NOx emissions shall not exceed 1.98 pounds per hour from each AGR/RTO unit based on a 3-hour average.

(5) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents operation shall be limited as follows:

(A) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 4,690,000 tons of CO_2 during the first 12 months of operation.

(B) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 6,430,000 tons of CO_2 during the second 12 months of operation.

(C) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1, 290,000 tons of CO_2 during the third 12 months of operation.

(D) Thereafter, the CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1,290,000 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of each month.

Gasifier Preheat Burners, identified as (EU-008 A - E):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0007 lb /MMBtu and shall use only natural gas or SNG.

(2) The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.056 lb CO/MMBtu and shall use good combustion practices.

(3) The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be not exceed 0.0006 lb SO_2/MMBtu and shall use natural gas or SNG.

(4) The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.10 lb NOx /MMBtu and shall use good combustion practices.

(5) The GHGs BACT for the Gasifier Preheat Burners shall be as follows:

A. The use of good engineering design; and

B. The use of natural gas or SNG.

C. The CO_2 emissions from the Gasifier Preheater Burners shall not exceed 6,438 tons CO_2 per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emergency Generators, identified as (EU-009 A and B):

The BACT for the Emergency generator has been established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM/PM10/PM2.5: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation, each.

(6) The total CO_2 emissions from the emergency engines (EU-009A/B and EU-010A/B/C) shall not exceed 84 tons CO_2 per twelve (12) consecutive month period from non-emergency operation, with compliance determined at the end of each month.

Firewater Pump Engines, identified as (EU-010 A - C):

The BACT for the firewater pump engines has been established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each firewater pumps shall not exceed 52 hours per year of non-emergency operation, each.

Process Area Solid Feedstock Conveying, storage and feedbin (EU-011 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) shall be limited through a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Incoming Solid Feedstock Material Handling System - Barge Unloading (EU-012A):

The PM, PM_{10} and $PM_{2.5}$ emissions from the barge unloading to hopper transfer point (EU-012A) operation shall be controlled by a wet suppression with a control efficiency of 90%.

Railcar Unloading to Rail Hoppers (EU-012G/H):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the railcar unloading to rail hoppers shall be controlled by a wet dust extraction system or baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Barge Unloading from Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Rail Hoppers Unloading to the Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Stacker Belt to the Radial Stacker (EU-012 L- M):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belts to the Radial Stacker shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU-012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction system or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Radial Stacker to the Pile (EU-012 N-O):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a Telescoping chute with dust collection.

(2) The PM and PM_{10} emissions shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ emissions shall not exceed 0.0015 gr/dscf.

Storage Pile (EU-012W/X):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Storage Piles (EU-012W/X) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Dozer Activity (EU-012P/Q):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Dozer Activities (EU-012P/Q) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor Belts (EU-012AA):

(1) An enclosed vent to a wet dust extraction system or a baghouse for control of PM, PM_{10} and $PM_{2.5}$ emissions.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Rod Mill Vent (EU-013A-D):

(1) The PM and PM_{10} emissions from each Rod Mill Vents shall not exceed 0.025 pounds per hour based on a 3-hour average.

(2) The $PM_{2.5}$ emissions from each Rod Mill Vent shall not exceed 0.0074 pounds per hour based on a 3-hour average.

ASU Regeneration Vent (EU-017A and B):

(1) The PM and PM_{10} emissions from each Air Separation Unit (ASU) shall not exceed 0.026 pounds per hour based on a daily average.

(2) The $PM_{2.5}$ emissions from the Air Separation Unit (ASU) shall not exceed 0.009 pounds per hour based on a daily average.

Wet Sulfuric Acid Plants (EU-015 A and B):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

(2) The H_2SO_4 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the H_2SO_4 emissions shall not exceed 0.15 pounds per ton of acid produced and 5 lb/hour, each, based on a 3-hour average.

(3) The CO emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall not exceed 18.7 pounds per hour, each based on a 3-hour average.

(4) The SO_2 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a peroxide scrubber, the SO_2 emissions shall not exceed 0.25 lb/ton acid produced and 8.3 lbs SO2 per hour, each based on a 24-hour block daily average.

(5) The NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be limited by the use of a selective catalytic reduction (SCR) when the flow to the SCR is at or above a temperature of 750 degrees F and the NOx emissions shall not exceed 10.2 pounds per hour NOx based on a 24-hour block daily average for each Wet Sulfuric Acid unit.

(6) The CO_2 emissions from the Wet Sulfuric Acid Plant operation shall not exceed 474,000 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

ASU and Main Cooling Tower (EU-016A and 016B):

The PM, PM_{10} and $PM_{2.5}$ emissions from the ASU Cooling Tower (EU-016A) and the Main Cooling Tower (EU-016B) shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and total dissolved solids shall not exceed 1500 ppm based on a daily average.

Sulfuric Acid Tanks (EU-027A - F):

The H_2SO_4 emissions from the Sulfuric Acid tanks shall be limited by the use of a fixed roof tank and submerged fill.

ZLD Spray Dryer (EU-032):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Zero Liquid Discharge (ZLD) spray dryer shall be controlled by a fabric filter baghouse and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed a 0.005 gr/dscf based on a 3 hour average.

(2) The CO emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.036 lb/MMBtu and shall use good combustion practices.

(3) The SO_2 emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall be limited through the use of natural gas or SNG.

(4) The NOx emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.035 lb/MMBtu and shall use a Low NOx Burner (LNB).

(5) The GHGs BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be as follows:

A. The CO_2 BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be the use of good engineering design and the use of natural gas or SNG.

B. The CO_2 emissions from the ZLD Spray Dryer shall not exceed 2,884 tons CO_2 per twelve (12) consecutive month period, with compliance determined at the end of each month.

Fugitive Leaks from piping (FUG & FUG-WSA):

(1) The BACT for fugitive leaks of CO and H_2SO_4 is no-controls.

(2) The BACT for the fugitive leaks of SO_2 in the WSA is the use of a Leak Detection and Repair (LDAR) program.

(3) The BACT for fugitive GHG emissions is the use of a leak detection and repair (LDAR) program for the natural gas and SNG piping and weekly audio/visual inspection of the CO_2 compressors while they are in operation in any week in which there are at least twenty-four (24) hours of operation of the CO_2 compressor to be inspected.

Fugitive Dust From Paved Roads (FUG-ROAD):

The PM, PM_{10} and $PM_{2.5}$ emissions from the paved road (FUG-ROAD) shall be controlled by 90 % by the use of;

(1) Paving all plant haul roads,
(2) Use of wet or chemical suppression
(3) Prompt cleanup of any spilled materials.

Front -end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) shall be controlled by a Wet Suppression or Chemical suppression with 90% control efficiency.

Electric Circuit Breaker (FUG-SF6):

The GHGs BACT for the Electrical Circuit Breaker (FUG-SF6) shall be the use of fully enclosed pressurized SF_6 circuit breakers with leak detection (low pressure alarm).

Hazardous Air Pollutants (HAPs) Minor Limits

The source has the uncontrolled potential to emit 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:

The emission units shall be limited as follows:

(a) The Acid Gas Recovery Units, identified as EU-007A/B, Methanol emissions shall be limited to less than nine (9.0) tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The Acid Gas recovery Units, identified as EU-007A/B, combined Hazardous Air Pollutants (HAPs) emissions shall be limited to less than 22.5 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The methanol emissions from the AGRs shall be calculated by the following equation:

Methanol emissions = Vent Flow x Methanol Conc. x (1 – Control Effic.)

Where:

Vent Flow = Total AGR vent flow to the thermal oxidizers (million SCF/period) to be monitored continuously by the Permittee.

Methanol Conc. = Methanol Concentration of the inlet to the thermal oxidizer (lbs methanol/million SCF of vent gas), as determined in the most recent stack test of the oxidizer. Until the initial testing is performed, the engineering estimate of 12.7 lbs methanol/million SCF shall be used.

Control Effic. = The control efficiency of the Regenerative Thermal Oxidizer as determined by stack test. Until the initial stack test is performed, the engineering estimate of 99% control shall be used.

(d) The Permittee shall operate a carbon adsorber on the ZLD Inert Gas Vent. The carbon adsorber shall be used at all times the ZLD inert gas vent is in operation except during carbon adsorber maintenance, repair or carbon replacement. The system shall be designed with a carbon replacement interval of no less than once per year (based on maximum design flow rate and mercury concentration).

Compliance with the above limits and requirements and combined with the potential to emit HAP emissions from all other emission units will limit the potential to emit from this source to less than ten (10) tons per year of any individual HAP and twenty-five (25) tons per year of any combination of HAPs and make the source an area source of HAPs.

Operating Restrictions during Gasifier Startup Flaring
During startup flaring of the gasifiers, the Permittee shall not test an emergency engine (EU-009A/B and EU-010A/B/C). This operating restriction shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

Alternative Emissions Limitation during Gasifier Startup Flaring

(a) During startup flaring of the gasifiers, NOx emissions from the AGR units (EU-007A/B) shall be limited to 2.97 lbs/hr combined from both AGR units (EU-007A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

(b) During startup flaring of the gasifiers, NOx emissions from the WSA units (EU-015A/B) shall be limited to 15.26 lbs/hr combined from both WSA units (EU-015A/B) and shall be applicable beginning when a starting up gasifier first begins to flare generated syngas and ends when the generated syngas begins diversion from the flare to the downstream AGR/WSA trains.

Operational Limits for the auxiliary Boilers
The total throughput of fuel to the two (2) natural gas-fired auxiliary boilers, identified as EU-005A/B, shall be limited to a total firing rate of 1430 billion Btu per twelve (12) consecutive month period, with compliance determined at the end of each month.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of emission units in the plant 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 1-7 (Actual Stack Height Provisions)
326 IAC 1-7 applies to exhaust stacks with potential particulate or sulfur dioxide emissions of 25 tons per year or more. 326 IAC 1-7-3(a) requires that new stacks meeting these criteria be constructed using either good engineering practice (GEP) or, at least, with a stack height sufficient to insure that emissions will not cause excessive ground level concentrations due to downwash, eddies, or wakes.

Each Regenerative Thermal Oxidizer Vent (EU-07) and each Wet Sulfuric Acid Plant Vent (EU-15) will have potential SO_2 emissions greater than 25 tons per year, so these stacks will be subject to this rule for SO_2. No other stacks at the proposed facility meet the applicability criteria.

326 IAC 2-6 (Emission Reporting)
Since this source is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program, this source is subject to 326 IAC 2-6 (Emission Reporting). In accordance with the compliance schedule in 326 IAC 2-6-3, an emission statement must be submitted triennially. The first report is due no later than July 1, 2014, and subsequent reports are due every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(2).

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

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is subject to the requirements of 326 IAC 6-5 because it is a new source of fugitive particulate matter emissions, located anywhere in the state, requiring a permit as set forth in 326 IAC 2, which has not received all the necessary preconstruction approvals before December 13, 1985.

326 IAC 3-5 (Continuous Monitoring of Emissions)
The auxiliary boilers, identified as EU-05A and EU-05B are subject to the monitoring requirements of 326 IAC 3-5 because they are fossil fuel fired steam generators that have a heat input capacity of greater than 100 MMBtu per hour.

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A), a continuous monitoring system for NOx shall be installed, calibrated, maintained, and operated to measure the NOx emissions from the exhaust of the two auxiliary boilers, identified as EU-05A and EU-05B.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(C) and (D), a continuous monitoring system shall be installed, calibrated, maintained, and operated to measure Nitrogen Oxide (NOx) and either O_2 or CO_2 emissions from auxiliary boilers, identified as EU-05A and EU-05B since the boilers are subject to NOx monitoring under 40 CFR 60.

(c) Pursuant to 326 IAC 3-5(c) (2) (A) (i) the Auxiliary Boiler are exempts from continuous opacity monitoring because it burns only gaseous fuels. SO_2 monitoring is not required because the boiler will not be subject to SO_2 monitoring under 40 CFR 60 and will not have SO_2 air pollution control equipment.

(d) The requirements of 326 IAC 3-5 also applies to "sulfuric acid plants or production facilities of greater than 300 tons per day acid production capacity". 326 IAC does not contain a definition of "sulfuric acid plants or production facilities", other than in 40 CFR 60 Subpart H incorporated by reference at 326 IAC 12 which exempts processes with the primary purpose of reducing atmospheric emissions of sulfur compounds.

The IG Sulfuric Acid Plants are facilities where the conversion to sulfuric acid is performed primarily as a means of reducing atmospheric emissions of SO_2 or other sulfuric compounds. Since the Indiana Gasification sulfuric acid plants do not meet the definition of sulfuric acid production unit in Subpart H, the sulfuric acid plants are not be subject to the requirements of 326 IAC 3-5.

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
(a) 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 auxilliary boilers, identified as EU-05A and EU-05B shall not exceed 0.19 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 816.0 MMBtu/hr.

However, 326 IAC 6-2-4 (h) states that if a limitation established by this rule is inconsistent with a limitation required by the permit regulations, then the permit regulation limit will prevail. Since the BACT emissions limit is significantly more stringent than the above calculated limit, compliance with the BACT particulate matter limits renders the above rule (326 IAC 6-2-4) not applicable to these auxiliary boilers.

(b) The gasifier startup burners, identified as EU-08 and WSA preheat burners, identified as EU-15 are process heaters and not indirect heat exchangers pursuant to 40 CFR 60 Subpart Dc, therefore, these emission units are not subject to the requirements of 326 IAC 6-2.

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

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the Process Area Solid Feedstock Handling Operations (EU-11A/B) and Wind Erosion from the coal/coke piles (EU-12W/X) shall not exceed 67.2 pounds per hour when operating at a process weight rate of 430 tons per hour. The pound per hour limitation was calculated with 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

The BACT limit for these emission units are much more stringent. Therefore, pursuant to 326 IAC 6-3-1(b), these emission units are exempt from the requirements of 326 IAC 6-3-2.

(b) Pursuant to 326 IAC 6-3-1(b)(14), EU-13 Rod Mill Air Eductors and EU-17 ASU Sieve Regeneration are exempt from this rule because potential PM emissions are less than 0.551 lb per hour.

(c) Pursuant to 326 IAC 6-3-1(b)(14), the noncontact cooling tower systems, trivial activities as defined at 326 IAC 2-7-1(40), processes with potential emissions less than 0.551 lb/hr, and where a particulate limit established under BACT or another rule is more stringent are exempt from this rule.

326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations)

(a) This Acid gas removal (AGR) unit and the Wet sulfuric acid (WSA) are subject to the requirements of 326 IAC 7-1.1-2 because the emission units have potential to emit greater than 25 tons of SO_2 per year, each. However, pursuant to this rule, there are no specific SO_2 emission limitations for the combustion of natural gas. Therefore, the requirements of 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) are not applicable to the Acid gas removal (AGR) units and the Wet sulfuric acid (WSA) at this source.

(b) All other emission units are not subject to the requirements of 326 IAC 7-1.1-2 because they have the potential to emit less than 25 tons of SO_2 per year. Therefore, the requirements of 326 IAC 7-1.1-2 (Sulfur Dioxide Emission Limitations) are not applicable to any emission unit at this source.

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

(a) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The uncontrolled VOC emissions from the Acid Gas Recovery Unit Vents, identified as EU-007A/B are greater than 25 tons per year.

Pursuant to 326 IAC 8-1-6, IDEM has established BACT for VOC for the Acid Gas Recovery Unit Vents, identified as EU-007A/B as follows:

The VOC emissions from the Acid Gas Recovery Unit vents (EU-007A/B) shall be controlled through the use of a Regenerative Thermal Oxidizer on each vent and the VOC emissions for each vent shall not exceed 1.05 pounds per hour based on a 3-hour average.

(b) The uncontrolled VOC emissions from all other emission units are less than 25 tons per year, therefore, all other emission units at this source are not subject to the requirements of 326 IAC 8-1-6 (New Facilities; General Reduction Requirements).

326 IAC 8-4-6 (Gasoline Dispensing Facilities)
Pursuant to 326 IAC 8-4-1(f) and 326 IAC 8-4-6 the requirements of this rule do not apply to the gasoline storage tank at a gasoline dispensing facility, though this facility is constructed after July 1, 1989 the facility has a monthly gasoline throughput of less than ten thousand (10,000) gallons per month.

326 IAC 8-9-1 (Volatile Organic Liquid Storage Vessels)
Pursuant 326 IAC 8-9-1(a) this rule only applies to VOL storage vessels located in Clark, Floyd, Lake, or Porter County. This source is located in Spencer County.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972 and has CO emissions of more than 100 tons per year. There are no applicable CO emission limits, under this state rule, established for this type of operation.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Section (4)(a) of this rule, requires that the PSD application shall contain an analysis of ambient air quality in the area that the major stationary source would affect for pollutants that are emitted at major levels or significant amounts. Indiana Gasification LLC has submitted an air quality analysis, which has been evaluated by IDEM's Technical Support and Modeling Section. See details in Appendix C.

NAAQS modeling for the 24-hour time-averaging period for $PM_{2.5}$was conducted and compared to the respective NAAQS limit. For the 24-hour modeling, two scenarios were examined and had to do with feedstock deliveries both by truck or train. These operations cannot occur at the same time due to equipment and logistical constraints. OAQ modeling results are shown in Table 5a. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years plus background were not below the NAAQS limit and a culpability analysis was required.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) of this rule, requires that the air quality impact analysis required by this section shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes required by this section shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines cited in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to public comment procedures set forth in 326 IAC 2-1.1-6.

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.

It is estimated that approximately 200 additional jobs will be created as a result of the proposed project. Most of the employees will be drawn from surrounding areas. 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: Moderately thick loess over weathered loamy glacial till, discontinuous loess over weathered sandstone and shale, discontinuous loess over weathered limestone and shale.

Due to the agricultural nature of the land, crops in the Spencer County area consist mainly of corn, sorghum, wheat, soybeans, and oats (2002 Agricultural Census for Spencer County). The maximum modeled concentrations for Indiana Gasification, LLC are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishop’s cap and horsetail, and milkweed (Flora of Indiana – Charles Deam). Livestock in Spencer County consist mainly of hogs, cattle, and sheep (2002 Agricultural Census for Spencer 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 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, 6 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 1 reptile, 3 mollusks, 1 fish, 4 birds, and 2 mammals have habitat within Spencer 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 plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. At this time 8 state endangered plant species are found in Spencer County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

326 IAC 2-2-6 (Increment Consumption Requirements)
326 IAC 2-2-6(a) requires that any demonstration under section 5 of this rule shall demonstrate that increased emissions caused by the proposed major stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentration of sulfur dioxide, particulate matter, and nitrogen dioxide indicated in subsection (b)(1) of this rule.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source. See detailed analysis in Appendix C.

326 IAC 2-2-8 (Source Obligation)
(1) Pursuant to 2-2-8(1), approval to construct, shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is

discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time.

(2) Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

326IAC 2-2-10 (Source Information)
The Permittee has submitted all information necessary to perform an analysis or make the determination required under this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or section 8 of this rule.

326 IAC 24 Clean Air Interstate Rule (CAIR)
The Clean Air Interstate Rule (CAIR) is not applicable to any source at the IG facility. CAIR applies to fossil-fuel fired boilers serving a generator with a nameplate capacity of more than 25 MW and producing electricity for sale. The Auxiliary Boilers (EU-05A/B) are fossil-fuel fired boilers serving a generator. However, pursuant to 326 IAC 24-1(b)(1)(B) the CAIR does not apply to a boiler serving a generator that supplies, in any calendar year, less than 1/3 of the unit's potential electric output capacity or 219,000 MW-hours (25 MW), whichever is greater, to any utility power distribution system for sale. Electricity produced by the Indiana Gasification facility is intended to balance the energy requirements of the facility. This electricity will normally be produced from process generated steam in a steam turbine generator, and any excess that is distributed for sale will not exceed 1/3 of the potential generation. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 24.

326 IAC 21 Acid Deposition Control
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements. This source is not subject to the requirements of 326 IAC 21 because it does not sell greater than 1/3 its generated electric. This regulation applies to electric utility generating units that supply greater than 1/3 their potential electrical output and greater than 219,000 MWe-hrs (25MW) actual electrical output on an annual basis to any utility power distribution system for sale. Therefore, the auxiliary boilers, identified as EU-05A and EU-05B are not subject to the requirements of 326 IAC 21.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source’s failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to this modification are as follows:

Testing Requirements

(a) Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Auxiliary Boiler (A-B) -005	No control	not later than 180 days after initial startup of the first gasifier	CO	one time testing	326 IAC -2-2-3
Auxiliary Boiler (A-B) -005	No control	not later than 180 days after initial startup of the first gasifier	Thermal Efficiency	one time testing	326 IAC -2-2-3
Acid Gas Recovery Unit (A-B) -007	No Control	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	NOx	one time testing	326 IAC -2-2-3
Acid Gas Recovery Unit (A-B) -007	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	CO	Every five (5) years	326 IAC -2-2-3
Acid Gas Recovery Unit (007 A-B)	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	VOC	Every five (5) years	326 IAC 8-1-6
Acid Gas Recovery Unit (007 A-B)	Regenerative Thermal Oxidizer	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	HAPs (Methanol)	Every five (5) years	HAPs Minor Limit
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011	Baghouse	No later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3
Incoming Solid Feed stock handling (Coal/petcoke) (B-V, Y-AC) - 012	Dust Extraction, or Baghouse, Telescoping Chute/ Wet Suppression	No later than 180 days after initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Wet Sulfuric Acid Plant (A-B) - 015	Mist eliminator/Peroxide Scrubber	not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} $PM_{2.5}$ and H_2S0_4	Every five (5) years	326 IAC -2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	No Control	not later than 180 days after initial startup of the second gasifier but not later than 365 days after the initial startup of the first gasifier	CO	one time testing	326 IAC -2-2-3
ZLD Spray Dryer	Baghouse	not later than 180 days after initial startup of the fourth gasifier, but not later than 365 days after the initial startup of the first gasifier	PM, PM_{10} and $PM_{2.5}$	Every five (5) years	326 IAC -2-2-3

Stack testing of the ZLD Spray Dryer for NOx emission is not justified because of its small size and low emissions rate. NOx emissions from this source results from combustion of natural gas in a standard gas burner incorporated in the dryer design. The maximum capacity of the burner is only 5.6 MMBtu per hr and NOx emissions are less than one (1) ton per yr. Stack testing this small, uncontrolled source is not required for this unit.

Stack testing the Gasifier Preheat Burners for NOx emissions is not justified because it is technically very difficult and also because the burners are each such small sources. There are five (5) preheat burners, which are used intermittently during gasifier startups and/or to keep a spare gasifier in hot standby. All five burners added together, over the course of a year, average only 12 MMBtu per hr (2.4 MMBtu/hr each) and collectively only emit 5.26 tons per year of NOx. Also, it would be technically very difficult to test these emissions because of the unique process configuration. The burners are used inside of the gasifier vessel to warm it prior to startup. Unlike a conventional heater or boiler, the gasifier vessels are fully enclosed vessels and can't rely on natural draft for combustion air or for venting combustion exhaust. Instead this is accomplished by use of a steam eductor to draw out the combustion exhaust. The steam eductor injects steam directly into the exhaust flow. The resultant vent stream is mostly water vapor, with only a small amount of exhaust. The extremely high moisture content of this vent stream would be technically very difficult to stack test. Because of these difficulties and the small size of these sources, stack testing is not required for this emission unit.

(b) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limit or Requirement
Syngas Hydrocarbon Flare (EU-001)	Flare pilot flame	Continuous	N/A	Response steps	326 IAC 2-2-3
	Total gas flow				
	Visible Emissions	Daily			
Acid Gas Flare (EU-002) (Thermocouple)	Flare pilot flame	Continuous	N/A	Response steps	326 IAC 2-2-3
	Visible Emissions	Daily			
Acid Gas Recovery Unit (A-B) -007 (RTO)	Temperature	Continuous	> 1600 °F		

Control	**Parameter**	**Frequency**	**Range/ Value**	**Excursions and Exceedances**	**Limit or Requirement**
Acid Gas Recovery Unit (A-B) -007 (water wash tower)	Water wash flow rate	Continuous	N/A	Response steps	HAPs Minor Limit
Wet Sulfuric Acid Plant (A-B) - 015 (Peroxide Scrubber)	Compliance with the SO_2 emissions limit	Continuous (w/CEM)	8.3 lb/hr each WSA (24 hr average)	Response steps	326 IAC 2-2-3 and 40 CFR 64
Wet Sulfuric Acid Plant (A-B) - 015 (SCR)	Temperature	Continuous when SCR is not operating	N/A	Response steps	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015 (Mist Eliminator/Peroxide Scrubber)	Flow Rate	Daily	N/A	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Pressure Drop		1.0 - 5.0 inches		
Wet Sulfuric Acid Plant (A-B) - 015 (SCR)	compliance with NOx emission limit	Daily	NA	Response steps	326 IAC 2-2-3 and 40 CFR 64
Process Area Solid Feedstock Handling (Coal/Petcoke) - 011 (Baghouse)	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock Radial Stacker (N-O) -012 (Fabric Filters/Telescoping Chute	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock open handling (A,P,Q,W,X) -012 (Wet Suppression)	Visible Emissions	Daily	Normal-Abnormal	Response steps	326 IAC 2-2-3 and 40 CFR 64
Incoming Solid Feed stock enclosed handling (B-M, R-V, Y-AC) EU- 012 Wet Dust Extractor or Baghouse	Water flow rate	Daily	> 1. 5 gpm	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Water Pressure Drop		1.0 to 5.0 inches		
	Visible Emissions		Normal-Abnormal		
Incoming Solid Feed stock enclosed handling (R-S) EU-012 Wet Dust Extractor or Baghouse	Water flow rate	Daily	> 5.0 gpm	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Water Pressure Drop		1.0 to 5.0 inches		
	Visible Emissions		Normal-Abnormal		
ZLD Spray Dryer - 032(Baghouse)	Water Pressure Drop	Daily	1.0 to 5.0 inches	Response steps	326 IAC 2-2-3 and 40 CFR 64
	Visible Emissions		Normal-Abnormal		
Methanol Storage Tank (Condenser)	Refrigerant Temperature	Continuous	< 0°F	Response steps	40 CFR 64
ZLD Vent EU-033 Sulfided Carbon Adsorbent	Pressure Drop	Weekly	N/A	Response steps	HAPs Minor Limit

(c) Continuous Emission Monitoring System (CEMs) Requirements applicable to this source are as follows:

Control	Parameter	Frequency	Value	Excursions and Exceedances	Requirement
Auxiliary Boiler (A-B) -005	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	SO_2 CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
Wet Sulfuric Acid Plant (A-B) - 015	CO_2 CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3

Conclusion and Recommendation

The construction and operation of this proposed new source shall be subject to the conditions of the attached proposed Part 70 PSD/New Source Construction and operating permit No.T147-30464-00060. The staff recommends to the Commissioner that this Part 70 PSD/New Source Construction and operating permit be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) (234-5257*)* or toll free at 1-800-451-6027 extension (4-5257).

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

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

Appendix A: Emissions Calculations
Emission Summary

Source Name: Indiana Gasification, LLC
Source Location: CR 200 N and Based Road, Rockport, IN 47635
Permit Number: 147-30464-00060
Permit Reviewer: Josiah Balogun
Date: 30-Jun-2011

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	H_2SO_4 (tons/yr)	H_2S (tons/yr)	Pb (tons/yr)	Hg (tons/yr)	Methanol (tons/yr)	Total HAPs (tons/yr)	CO_2 (tons/yr)	Total CO_2e (tons/yr)
Emission Unit															
Syngas Hydrocarbon Flare (001)	28.12	28.12	0.41	3.045	0.43	301956	377.65	0	0.06	3.4E-06	1.90E-06	0	0	816,190	857,135
Acid Gas Flare (002)	0.01	0.01	0.01	0.001	0.023	0.06	0.23	0	0	3.4E-06	1.90E-06	0	0	136	136
Auxiliary Boiler (005A-B)	26.93	26.93	5.62	2.13	19.49	130.13	45.2	0	0	0.033	6.10E-03	0	6.69	422401	422816
Acid Gas Recovery Unit (007A-B)	3.8	3.8	2.46	41.62	39.64	632.8	25.99	0	7.47	0.000986	8.20E-04	10.54	37.83	1,289,735	1,290,000
Gasifier Preheat Burners (008A-E)	0.3	0.3	0.04	0.23	2.15	22.1	39.4	0	0	0.0003	6.50E-04	0	0.75	46,383	46,405
Emergency Diesel Generator (009A-B)	0.03	0.03	0.003	0.008	0.015	0.019	7.28	0	0	0.00E+00	0.00E+00	0	0	350.88	352.1
Emergency Firewater Engine (010A-C)	0.08	0.08	0.0078	0.0046	0.164	0.6	2.35	0	0	0.00E+00	0.00E+00	0	0	199.9	200.6
Process Area Solid Feedstock (011)	5.49	5.49	1.94	0	0	0	0	0	0	0.00105	5.40E-06	0	0	0	0
Incoming Solid Feedstock Handling (012A-AC)	202.1	88.38	12.24	0	0	0	0	0	0	0.00E+00	8.94E-06	0	0	0	0
Rod Mill (013A-D)	0.44	0.44	0.13	0	0	0	0	0	0	0.00E+00	3.78E-07	0	0	0	0
Wet Sulfuric Acid Plant (015A-B)	43.8	43.8	43.8	72.76	0.0113	164.3	89.4	43.8	0	0.00044	3.52E-06	0	0	474000	474000
Cooling Tower -ASU (016A)	0.9	0.9	0.75	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Cooling Tower -Main (016B)	6.65	6.65	5.52	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
ASU Molecular Sieve Regeneration (017A-B)	1.1	1.1	0.08	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Slag Sump (023A-E)	0	0	0	0	0	0	0	0	0.1	0.00E+00	0.00E+00	0	0	0	0
Methanol De-Inventory Storage Tank (024)	0	0	0	0	0.16	0	0	0	0	0.00E+00	0.00E+00	0.16	0.16	0	0
Fresh Methanol Storage Tank (025)	0	0	0	0	0.13	0	0	0	0	0.00E+00	0.00E+00	0.13	0.13	0	0
Sour Water Stripper Surge Tank (026)	0	0	0	0	0.004	0	0	0	0.54	0.00E+00	0.00E+00	0	0	0	0
Sulfuric Acid Storage Tank (027A-F)	0.0015	0.0015	0.0015	0	0	0	0	0.0015	0	0.00E+00	0.00E+00	0	0	0	0
Diesel Fuel Storage Tank (029)	0	0	0	0	0.35	0	0	0	0	0.00E+00	0.00E+00	0	0.07	0	0
Gasoline Fuel Storage Tank (030)	0	0	0	0	0.1	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Triethylene Glycol Storage Tank (031)	0	0	0	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
ZLD Spray Drier (032)	0.51	0.51	0.48	0.015	0.13	0.89	0.86	0	0	0.000071	4.10E-05	0	0.046	2882.8	2886
ZLD Inert Gas Vent (033)	0	0	0	0	0	0	0	0	0	0.00E+00	6.53E-02	0	0	203.67	203.67
EU-034A and 034C	0.041	0.017	0.0024	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Fugitive Emissions															
Gasification, Shift Conv. AGR, methanation (FUG)	0	0	0	0	27.46	9.45	0	0	0.38	0.00E+00	0.00E+00	7.15	7.58	48.86	325.6
Fugitive Emission - WSA (FUG-WSA)	0	0	0	0.1	0	0	0	0.09	3.74	0.00E+00	0.00E+00	0	0	4	4
Plant Haul Roads (FUG-ROAD)	2.63	0.53	0.13	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Electric Circuit Breakers (FUG-SF6)	0	0	0	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	72
Total Emissions	**322.93**	**207.09**	**73.63**	**119.91**	**90.26**	**302916**	**588.36**	**43.89**	**12.29**	**0.04**	**7.29E-02**	**17.98**	**53.26**	**3052535.11**	**3094535.97**

Emission Summary

Source Name: Indiana Gasification, LLC
Source Location: CR 200 N and Based Road, Rockport, IN 47635
Permit Number: 147-30464-00060
Permit Reviewer: Josiah Balogun
Date: 30-Jun-2011

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	H_2SO_4 (tons/yr)	H_2S (tons/yr)	Pb (tons/yr)	Hg (tons/yr)	Methanol (tons/yr)	Total HAPs (tons/yr)	CO_2 (tons/yr)	Total CO_2e (tons/yr)
Emission Unit															
Syngas Hydrocarbon Flare (001)	0.44	0.44	0.41	1.97	0.03	23.5	6.07	0	0.04	3.4E-06	1.90E-06	0	0	13302	13,343
Acid Gas Flare (002)	0.01	0.01	0.01	0.001	0.023	0.06	0.23	0	0	3.4E-06	1.90E-06	0	0	136	136
Auxiliary Boiler (005A-B)	5.62	5.62	5.62	0.44	4.07	27.15	9.43	0	0	0.0022	1.3E-03	0	1.4	88167	88254
Acid Gas Recovery Unit (007A-B)	2.46	2.46	2.46	26.98	8.96	410.27	16.85	0	0.1	0.00096	5.30E-04	9	22.5	1,289,735	1,290,000
Gasifier Preheat Burners (008A-E)	0.04	0.04	0.04	0.03	0.3	3.08	5.51	0	0	0.00016	9.05E-05	0	0.1	6438	6444
Emergency Diesel Generator (009A-B)	0.003	0.003	0.0003	0.0008	0.0015	0.019	0.76	0	0	0.00E+00	0.00E+00	0	0	84	84
Emergency Firewater Engine (010A-C)	0.008	0.008	0.0078	0.0005	0.017	0.06	0.24	0	0	0.00E+00	0.00E+00	0	0		
Process Area Solid Feedstock (011)	3.8	3.8	1.86	0	0	0	0	0	0	0.00103	5.40E-06	0	0	0	0
Incoming Solid Feedstock Handling (012A-AC)	5.45	3.25	0.88	0	0	0	0	0	0	0.00E+00	8.94E-06	0	0	0	0
Rod Mill (013A-D)	0.44	0.44	0.13	0	0	0	0	0	0	0.00E+00	3.80E-07	0	0	0	0
Wet Sulfuric Acid Plant (015A-B)	42.59	42.59	42.59	70.74	0.01	159.7	86.93	42.59	0	6.1E-06	3.52E-06	0	0	474000	474000
Cooling Tower -ASU (016A)	0.9	0.9	0.7	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Cooling Tower -Main (016B)	6.65	6.65	5.19	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
ASU Molecular Sieve Regeneration (017A-B)	0.22	0.22	0.08	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Slag Sump (023A-E)	0	0	0	0	0	0	0	0	0.1	0.00E+00	0.00E+00	0	0	0	0
Methanol De-Inventory Storage Tank (024)	0	0	0	0	0.16	0	0	0	0	0.00E+00	0.00E+00	0.16	0.16	0	0
Fresh Methanol Storage Tank (025)	0	0	0	0	0.13	0	0	0	0	0.00E+00	0.00E+00	0.13	0.13	0	0
Sour Water Stripper Surge Tank (026)	0	0	0	0	0.004	0	0	0	0.54	0.00E+00	0.00E+00	0	0	0	0
Sulfuric Acid Storage Tank (027A-F)	0.0015	0.0015	0.0015	0	0	0	0	0.0015	0	0.00E+00	0.00E+00	0	0	0	0
Diesel Fuel Storage Tank (029)	0	0	0	0	0.35	0	0	0	0	0.00E+00	0.00E+00	0	0.07	0	0
Gasoline Fuel Storage Tank (030)	0	0	0	0	0.1	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Triethylene Glycol Storage Tank (031)	0	0	0	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
ZLD Spray Dryer (032)	0.51	0.51	0.48	0.015	0.13	0.89	0.86	0	0	0.000071	4.10E-05	0	0.046	2882.8	2886
ZLD Inert Gas Vent (033)	0	0	0	0	0	0	0	0	0	0.00E+00	3.60E-04	0	0	203.67	203.67
EU-034A and 034C	0.04	0.017	0.0024	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Fugitive Emissions															
Gasification, Shift Conv. AGR, methanation (FUG)	0	0	0	0	1.61	9.45	0	0	0.37	0.00E+00	0.00E+00	0.37	0.38	19	21
Fugitive Emission - WSA (FUG-WSA)	0	0	0	0.003	0	0	0	0.09	3.74	0.00E+00	0.00E+00	0	0	4	4
Plant Haul Roads (FUG-ROAD)	0.45	0.09	0.022	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	0
Electric Circuit Breakers (FUG-SF6)	0	0	0	0	0	0	0	0	0	0.00E+00	0.00E+00	0	0	0	72
Total Emissions	**69.63**	**67.05**	**60.48**	**100.18**	**15.90**	**634.18**	**126.88**	**42.68**	**4.89**	**0.004**	**0.00231**	**9.66**	**24.79**	**1874971.47**	**1875447.67**

FLARE SOURCES

NAME Hydrocarbon / Gasifier Start-up Flare

Unit ID: 001

STACK DATA

HEIGHT 300 ft

DIAMETER 6 ft

EMISSIONS: Scenario 1: Gasifier Start-Up Syngas Flaring

hr/yr = 8760

Firing Rate = 861.7 MMBtu/hr

CO DRE 0 %

Pollutant	H2S in Syngas lb-mol/hr	COS in Syngas lb-mol/hr	Raw Syngas Flared lb-mol/hr	CO in Syngas Mol %	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	--	--	--	--	6.42	6.42	28.12
PM$_{2.5}$					0.09	0.09	0.41
SO$_2$	0.01	0	--	--	0.70	0.70	3.045
NOx	--	--	--	--	86.17	86.17	377.42
CO	--	--	18237.12	13.50	68939.73	68939.73	301956.00
H2S (TAP)	0.01	--	--	--	0.01	0.01	0.03
COS (TAP)(VOC)	--	0.00	--	--	0.00	0.00	0.00
Other VOC	--	--	--	--	0.09	0.09	0.41
Total VOC					0.09	0.09	0.41

EMISSIONS: Scenario 2: Gasifier Start-Up Flare Pilot Burners Operating

hr/yr = 8,760

Pilot Firing Rate = 0.27 MMBtu/hr

AP-42 Heating Value = 1,020 Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	0.0020	0.0020	0.0087
PM$_{2.5}$	0.0019	0.0019	0.0081
SO$_2$	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.06
VOC	0.005	0.005	0.02
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

TOTAL STARTUP FLARING AND PILOT

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM$_{10}$	6.422	6.42	28.13
PM$_{2.5}$	0.095	0.09	0.41
SO$_2$	0.70	0.70	3.046
NOx	86.22	86.22	377.65
CO	68939.74	68939.74	301956.05
H2S (TAP)	0.013	0.01	0.06
COS (TAP)(VOC)	0.00	0.00	0.00
Total VOC	0.0982	0.09	0.43
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

Calculations:

Scenario 1:

Emissions (SO2)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) + COS in Syngas (lb-mol/hr) X 64.063 lb/mol
Emissions (CO)(Avg. lb/hr)=(Raw Syngas flared (lbmols/hr) X CO in Syngas (mol %)/100) X 28.01 lb/mol X (100 - CO DRE)/100
Emissions (H2S)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) X 34.08 lb/mol X 2/100
Emissions (COS)(Avg. lb/hr)=COS in Syngas (lb-mol/hr) X 60.0764 lb/mol X 2/100
Emissions (NOx, PM_{10}, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenarios 2 and 3:

Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions-Pilot Case (SO2, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenario 1	NOx	PM_{10}	VOC
Factor (lb/MMBtu)	0.100	0.007	0.0001

Sources: NOx and PM_{10} for Syngas are based on values from vendor supplied data. VOC for Syngas = 2% of AP-42 Section 1.4 "Natural Gas Combustion" Table 1.4-2

Scenario 2	PM_{10}	SO_2
Factor (lb/MMscf)	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Scenario 2	NOx	CO	VOC
Factor (lb/MMBtu)	0.200	0.050	0.020

Sources: NOx and CO, and VOC are based on values from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

DRE for H2S and COS is considered as 98%.
DRE for CO is considered as 99.5%.
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs for natural gas to the pilot are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4. Flared gas is primarily CO and H2 - HAPs assumed negligable.
Scenario 1: Gasifier Start-up Syngas Flaring
Scenario 2: Gasifier Start-up Flare Pilot Burners Operating
Scenario 3: Normal Operations-Purge Gas and Pilot Gas Flaring

Number Shutdown Flaring Events / year = 15
Flaring Event Duration (hrs) = 3
Firing Rate (MMBtu/Event) = 34.26

SHUTDOWN FLARING

Pollutant	Average Emissions lb/event	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.260	0.09	0.002
$PM_{2.5}$	0.260	0.09	0.002
SO_2	255.62	85.21	1.917
NOx	3.43	1.14	0.026
CO	21.22	7.07	0.159
H2S (TAP)	2.660	0.89	0.020
COS (TAP)(VOC)	0.20	0.07	0.002
VOC	0.0037	0.00	0.000

GHG Emissions from Gasifier Start-up

The feed to the gasifier flare during the start-up of a gasifier contains CO and CO2, but no other carbon compounds. A mass balance was used to determine the CO2 and N2O emissions. There will be no CH4 emissions. The GHG Subpart Y (Refinery) flare equations are not applicable; however, the Subpart Y equation for N2O will be used to conservatively estimate N2O emissions.

	lb/hr	TPY	MT/yr
CO2 for Gasifier Flare =	185,818.1	813,883.3	738354.9

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF}\right)$$

Equation Y-5

N_2O = Annual nitrous oxide emissions from flared gas (metric ton N_2O/year)

CO_2 = Emission rate of CO_2 from flared gas calculated (metric ton/year)

EmF_{N2O} = Default N_2O emission factor for “Petroleum Products” from Table C-2 of subpart C (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu) = 0.0006

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

N2O for Gasifier Flare = 7.384 MT

GHG Emissions from Pilot

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123.2 MT

$$CH_4 \, or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Hydrocarbon / Gasifier Start-up Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

Startup

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	738,355	1	738,355		
CH4	0	21	0		
N2O	7.384	310	2,288.9		
		TOTAL =	740,644	816,190	TPY CO2

Shutdown

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	36,918	1	36,918		
CH4	0	21	0		
N2O	0.369	310	114.4		
		TOTAL =	37,032	40,809	TPY CO2

Shutdown flared gas volume on an annual basis is 5% of startup flared gas volume.

Pilot

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	123.2	1	123.2		
CH4	0.0023	21	0.05		
N2O	0.0002	310	0.07		
		TOTAL =	123.3	136	TPY CO2

NAME Acid Gas Flare

Unit ID: 002

The Acid Gas Flare normally operates on pilot gas (natural gas) only. During an upset, acid gases can be routed to this flare.

STACK DATA

HEIGHT	300	ft
DIAMETER	1.6	ft

EMISSIONS: Acid Gas Flare Pilot Only

hr/yr =	8,760	
Pilot Firing Rate =	0.27	MMBtu/hr
AP-42 Heating Value =	1,020	Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.0020	0.0020	0.0087
$PM_{2.5}$	0.0019	0.0019	0.0081
SO_2	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.058
VOC	0.005	0.005	0.023
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06
CO2	31.00	31.00	136

Calculations:
Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion Factor (lb/MMscf)	PM_{10}	SO_2
	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Flare Factor (lb/MMBtu)	NOx	CO	VOC	CO2
	0.200	0.050	0.020	116.890

Source: NOx, CO, and VOC factors from AP-42 Section 13.5 "Industrial Flares" Table 13.5-1

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O
1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Acid Gas Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	123	1	123
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	123

136 TPY CO2

COMBUSTION SOURCES

NAME Auxiliary Boiler

Unit ID: 005A & B

Emissions shown are for sum of two (2) boilers each at 408 MMBtu/hr

STACK DATA

HEIGHT	200	ft
DIAMETER	11	ft
GAS EXIT TEMP- Full rate - Natural Gas	310	°F
GAS EXIT TEMP- Full rate (Black Start) - Natural Gas	310	°F
GAS EXIT VELOCITY - Full rate - Natural Gas	48.73	fps
GAS EXIT VELOCITY - Full rate (Black Start) - Natural Gas	48.73	fps

COMBUSTION DATA

HEAT INPUT - Full rate - Natural Gas	816.33	MM Btu/hr
HEAT INPUT - Full rate (Black Start) - Natural Gas	816.33	MM Btu/hr
HEAT INPUT - Pilot Gas - Natural Gas	10.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS- Full rate - Natural Gas	8760	hr/yr
OPERATING HOURS - Full rate (Black Start) - Natural Gas	96	hr/yr

EMISSIONS: Full rate case - Natural Gas

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	6.08	6.08	26.64
$PM_{2.5}$	1.22	1.22	5.33
SO_2	0.48	0.48	2.10
NOx	10.20	10.20	44.69
CO	29.39	29.39	128.72
VOC	4.40	4.40	19.28
Total VOC HAPs	1.51	1.51	6.62
Mercury (HAP)	1.4E-03	1.4E-03	6.0E-03

EMISSIONS: Full rate (Black Start) case - Natural Gas

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	6.08	6.08	0.29
$PM_{2.5}$	6.08	6.08	0.29
SO_2	0.48	0.48	0.023
NOx	10.20	10.20	0.49
CO	29.39	29.39	1.41
VOC	4.40	4.40	0.21
Total VOC HAPs	1.51	1.51	0.073
Mercury (HAP)	1.4E-03	1.4E-03	6.6E-05

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	6.15	6.08	26.93
$PM_{2.5}$	1.28	6.08	5.62
SO_2	0.49	0.48	2.13
NOx	10.32	10.20	45.18
CO	29.71	29.39	130.13
VOC	4.45	4.40	19.49
Total VOC HAPs	1.53	1.51	6.69
Mercury (HAP)	1.4E-03	1.4E-03	6.1E-03

CALCULATIONS

Emissions (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Total Emissions (Avg. lb/hr) = Total TPY x 2,000 lb/ton / 8,760 hr/yr
Total Emissions (Max. lb/hr) = Highest Maximum lb/hr value from either case

Natural Gas Combustion Factor (lb/MMscf)	PM_{10}	VOC	SO_2	HAP
	7.600	5.50	0.60	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Natural Gas/SNG Combustion Factor (lb/MMBtu)	NOx	CO
	0.0125	0.036

Source: Emission factors for NOx and CO are based on vendor data for Low NOx burners (LNB), SCR and Flue Gas Recirculation.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.
To be conservative, SO2 emissions will be calculated assuming all scenarios fire natural gas. If SNG is fired, there will be no SO2 emissions as SNG is assumed to contain no sulfur.
To be conservative, the mercury factor for SNG (Coal-Coke) will be used for all cases.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 383,304 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 7.2294 MT
N2O = 0.7229 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Auxiliary Boiler	Volume of the gaseous fuel combusted	Annual	7,087,677,766	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	383,304	1	383,304
CH4	7.2	21	152
N2O	0.7	310	224
		TOTAL =	383,680

422,816 TPY CO2

COMBUSTION SOURCES

NAME AGR CO2 Regenerative Thermal Oxidizer

Unit ID: 007

There are 2 RTOs which share a common chimney (although there are separate stacks), and receive waste gas feeds from the Acid Gas Removal Unit.

Emissions are calculated for both cases (coal / coke and coal only) and the higher (conservative) value for each pollutant will be permitted.

STACK DATA

HEIGHT	200	ft
DIAMETER	9	ft
GAS EXIT TEMP	250	°F
GAS EXIT VELOCITY	60.5	fps

COMBUSTION DATA (max from either case)

HEAT INPUT: Two Units at full rate	77.62	MM Btu/hr
HEAT INPUT: One Unit at full rate	38.81	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	19.41	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8760	hr/yr
OPERATING HOURS: One Unit at full rate	8760	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.57	lb/hr
COS in Waste gas to each RTO =	2.00	lb/hr
CO in Waste gas to each RTO:	4673.99	lb/hr
Total Sulfur in Waste gas to each RTO:	1.60	lb/hr
Methanol in Waste Gas to each RTO:	80.20	lb/hr
H2S and COS DRE:		%
CO and Methanol DRE:		%

EMISSIONS: Two Units at Full Rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.58	0.58	2.53
$PM_{2.5}$	0.55	0.55	2.40
SO_2	6.33	6.33	27.73
NOx	3.95	3.95	17.32
CO	96.27	96.27	421.68
VOC	6.03	6.03	26.42
H2S (TAP)	1.14	1.14	4.98
COS (HAP)(VOC)	4.01	4.01	17.56
Methanol (HAP)(VOC)	1.60	1.60	7.03
Total VOC HAPs	5.76	5.76	25.22
Mercury (HAP)	1.2E-04	1.2E-04	5.5E-04

EMISSIONS: Two Units on Hot Standby

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.29	0.29	1.27
$PM_{2.5}$	0.01	0.01	0.06
SO_2	3.17	3.17	13.87
NOx	1.98	1.98	8.66
CO	48.14	48.14	210.84
VOC	3.02	3.02	13.21
H2S (TAP)	0.57	0.57	2.49
COS (HAP)(VOC)	2.00	2.00	8.78
Methanol (HAP)(VOC)	0.80	0.80	3.51
Total VOC HAPs	2.88	2.88	12.61
Mercury (HAP)	6.2E-05	6.2E-05	2.7E-04

EMISSIONS: One Unit at half rate - Conservatively assume Natural Gas for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.14	0.14	0.0017
PM$_{2.5}$	0.14	0.14	0.0017
SO$_2$	1.58	1.58	0.019
NOx	0.99	0.99	0.012
CO	24.07	24.07	0.29
VOC	0.53	0.53	0.006
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.0002
Methanol (HAP)(VOC)	0.40	0.40	0.0048
Total VOC HAPs	0.46	0.46	0.005
Mercury (HAP)	3.1E-05	3.1E-05	3.7E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.87	0.58	3.80
PM$_{2.5}$	0.56	0.56	2.46
SO$_2$	9.50	6.33	41.62
NOx	5.93	3.95	25.99
CO	144.48	96.27	632.81
VOC	9.05	6.03	39.64
H2S (TAP)	1.706	1.14	7.47
COS (HAP)(VOC)	6.01	4.01	26.35
Methanol (HAP)(VOC)	2.41	1.60	10.54
Total VOC HAPs	8.64	5.76	37.83
Mercury (HAP)	1.9E-04	1.2E-04	8.2E-04

CALCULATIONS

Emissions (PM$_{10}$) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions - Normal (SO2) (Avg. lb/hr) = S in Waste Gas to each RTO (lb/hr) X 2 X DRE/100 X Mw SO2 (lb/lb-mol) / Mw S (lb/lb-mol)
Emissions - Black-start (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx) (Avg. lb/hr) = Vendor Factor (lb/MMBtu) X Heat Input (MMBtu/hr)
Emissions (CO) (Avg. lb/hr) = Vendor Factor (lb/MMBtu) X Heat Input (MMBtu/hr) + CO in Waste Gas (lb/hr) X 2 X (1 - DRE)/100
Emissions (VOC) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr) + COS (lb/hr) + MeOH (lb/hr)
Emissions (COS, MeOH) (Avg. lb/hr) = lb in Waste Gas (lb/hr) X 2 X (1 - DRE)/100
Emissions for each Case (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Maximum Emissions for each Case (lb/hr) = Average Emissions
Emissions TPY Total = Sum of individual cases
Emissions (Avg. lb/hr) Total = TPY Total X 2,000 (lb/T) / (Total Hrs Operation)

Natural Gas Combustion	PM$_{10}$	VOC	SO$_2$	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM$_{10}$

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtuf)	0.05	0.036

Source: Emission factors for NOx and CO are based on information from vendor supplied data and the use of Low NOx burners.

Comments:

SO$_2$ emissions based on 98% conversion of sulfur in waste gas to SO$_2$. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
During "normal operations" the thermal oxidizer burns SNG (which contains no sulfur); during a black-start, it fires natural gas for the first 4 hours. Permitted emissions will conservatively be based on firing natural gas only.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

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Coal / Coke Case

COMBUSTION DATA

HEAT INPUT: Two Units at full rate	62.69	MM Btu/hr
HEAT INPUT: One Unit at full rate	31.35	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	15.67	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8760	hr/yr
OPERATING HOURS: One Unit at full rate	8760	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.56	lb/hr
COS in Waste gas to each RTO =	1.97	lb/hr
CO in Waste gas to each RTO:	4595.57	lb/hr
Total Sulfur in Waste gas to each RTO:	1.58	lb/hr
Methanol in Waste Gas to each RTO:	78.86	lb/hr
H2S and COS DRE:	98	%
CO and Methanol DRE:	99	%

EMISSIONS: Two Units at Full Rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.47	0.47	2.05
SO_2	6.22	6.22	27.23
NOx	3.19	3.19	13.99
CO	94.17	94.17	412.46
VOC	1.99	1.99	8.73
H2S (TAP)	1.12	1.12	4.90
COS (HAP)(VOC)	0.08	0.08	0.35
Methanol (HAP)(VOC)	1.58	1.58	6.91
Total HAPs	1.77	1.77	7.76
Mercury (HAP)	1.1E-04	1.1E-04	4.6E-04

EMISSIONS: One Unit at full rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.23	0.23	1.02
SO_2	3.11	3.11	13.616
NOx	1.60	1.60	6.99
CO	47.08	47.08	206.23
VOC	2.93	2.93	12.83
H2S (TAP)	0.56	0.56	2.449
COS (HAP)(VOC)	1.97	1.97	8.63
Methanol (HAP)(VOC)	0.79	0.79	3.45
Total HAPs	2.82	2.82	12.34
Mercury (HAP)	5.3E-05	5.3E-05	2.3E-04

EMISSIONS: One Unit at half rate - Conservatively assume Natural Gas (for SO2) and SNG (for Hg) for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.12	0.12	0.0014
SO_2	1.55	1.55	0.019
NOx	0.80	0.80	0.010
CO	23.54	23.54	0.28
VOC	0.50	0.50	0.0060
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.00024
Methanol (HAP)(VOC)	0.39	0.39	0.0047
Total HAPs	0.44	0.44	0.0053
Mercury (HAP)	2.6E-05	2.6E-05	3.2E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.70	0.47	3.07
SO_2	9.33	6.22	40.87
NOx	4.79	3.19	20.99
CO	141.32	94.17	618.97
VOC	4.92	2.93	21.57
H2S (TAP)	1.68	1.12	7.35
COS (HAP)(VOC)	2.05	1.97	8.98
Methanol (HAP)(VOC)	2.37	1.58	10.37
Total HAPs	4.59	2.82	20.11
Mercury (HAP)	1.6E-04	1.1E-04	6.9E-04

Natural Gas Combustion	PM_{10}	VOC	SO_2	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM_{10}

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.05	0.036

	Natural Gas	SNG
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 9,711 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1832 MT
N2O = 0.0183 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Coal / Coke Case	Volume of the gaseous fuel combusted	Annual	179,564,678	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	9,711	1	9,711
CH4	0.18	21	4
N2O	0.018	310	6
		TOTAL =	9,720

10,712 TPY CO2

Feeds to RTO (CO2 + combusted CO):
1,427,034 lb/hr at full rate per Eng. Design
20% percent of max vented per year.
1,250,082 tons/yr

1,134,067 MTCO2e 1,250,082 Subtotal TPY CO2

Total CO2e: 1,143,784 MTCO2e 1,260,793 Total TPY CO2e

Coal Only Case

COMBUSTION DATA

HEAT INPUT: Two Units at full rate	77.62	MM Btu/hr
HEAT INPUT: One Unit at full rate	38.81	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	19.41	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8760	hr/yr
OPERATING HOURS: One Unit at full rate	8760	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.57	lb/hr
COS in Waste gas to each RTO =	2.00	lb/hr
CO in Waste gas to each RTO:	4673.99	lb/hr
Total Sulfur in Waste gas to each RTO:	1.60	lb/hr
Methanol in Waste Gas to each RTO:	80.20	lb/hr
H2S and COS DRE:	98	%
CO and Methanol DRE:	99	%

EMISSIONS: Two Units at Full Rate (100%)

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.58	0.58	2.53
SO_2	6.33	6.33	27.73
NOx	3.95	3.95	17.32
CO	96.27	96.27	421.68
VOC	6.03	6.03	26.42
H2S (TAP)	1.14	1.14	4.98
COS (HAP)(VOC)	4.01	4.01	17.56
Methanol (HAP)(VOC)	1.60	1.60	7.03
Total HAPs	5.76	5.76	25.22
Mercury (HAP)	1.2E-04	1.2E-04	5.5E-04

EMISSIONS: One Unit at full rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.29	0.29	1.27
SO_2	3.17	3.17	13.87
NOx	1.98	1.98	8.66
CO	48.14	48.14	210.84
VOC	3.02	3.02	13.21
H2S (TAP)	0.57	0.57	2.491
COS (HAP)(VOC)	2.00	2.00	8.78
Methanol (HAP)(VOC)	0.80	0.80	3.51
Total HAPs	2.88	2.88	12.61
Mercury (HAP)	6.2E-05	6.2E-05	2.7E-04

EMISSIONS: One Unit at half rate (25%) - Conservatively assume Natural Gas (for SO2) and SNG (for Hg) for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.14	0.14	0.0017
SO_2	1.58	1.58	0.019
NOx	0.99	0.99	0.012
CO	24.07	24.07	0.29
VOC	0.53	0.53	0.0063
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.0002
Methanol (HAP)(VOC)	0.40	0.40	0.0048
Total HAPs	0.46	0.46	0.0055
Mercury (HAP)	3.1E-05	3.1E-05	3.7E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.87	0.58	3.80
SO_2	9.50	6.33	41.62
NOx	5.93	3.95	25.99
CO	144.48	96.27	632.81
VOC	9.05	6.03	39.64
H2S (TAP)	1.706	1.14	7.47
COS (HAP)(VOC)	6.01	4.01	26.35
Methanol (HAP)(VOC)	2.41	1.60	10.54
Total HAPs	8.64	5.76	37.83
Mercury (HAP)	1.9E-04	1.2E-04	8.2E-04

Natural Gas Combustion	PM_{10}	VOC	SO_2	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM_{10}

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.05	0.036

	Natural Gas	SNG
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 10,976 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.2070 MT
N2O = 0.0207 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Coal Only Case	Volume of the gaseous fuel combusted	Annual	202,961,074	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	10,976	1	10,976
CH4	0.21	21	4
N2O	0.021	310	6
		TOTAL =	10,987

12,108 TPY CO2

Feeds to RTO (CO2 + combusted CO):

1,458,491	lb/hr at full rate per Eng. Design
20%	percent of max vented per year.
1,277,638	tons/yr

	1,159,066 MTCO2e	1,277,638	subtotal TPY CO2
Total CO2e:	1,170,050 MTCO2e	1,289,746	Total TPY CO2e

Max CO2e: 1,170,050 MT/yr

NAME Gasifier Start-up Preheat Burner A

Unit ID: 008 A

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	8760	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0587
$PM_{2.5}$	0.002	0.002	0.0073
SO_2	0.011	0.011	0.0464
NOx	1.800	1.800	7.88
CO	1.008	1.008	4.42
VOC	0.097	0.097	0.43
Total VOC HAPs	0.033	0.033	0.15
Mercury (HAP)	3.0E-05	3.0E-05	1.3E-04

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion Factor (lb/MM scf)	SO_2
	0.6

Natural Gas Combustion Factor (lb/MM Btu)	PM_{10}	NOx	CO	VOC
	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 8,414 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1587 MT
N2O = 0.0159 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner A	Volume of the gaseous fuel combusted	Annual	155,576,471	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	8,414	1	8,414
CH4	0.2	21	3
N2O	0.0	310	5
		TOTAL =	8,422

9,281 TPY CO2

NAME Gasifier Start-up Preheat Burner B

Unit ID: 008 B

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	8760	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0587
$PM_{2.5}$	0.002	0.002	0.0073
SO_2	0.011	0.011	0.0464
NOx	1.800	1.800	7.88
CO	1.008	1.008	4.42
VOC	0.097	0.097	0.43
Total VOC HAPs	0.033	0.033	0.15
Mercury (HAP)	3.0E-05	3.0E-05	1.3E-04

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 8,414 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1587 MT
N2O = 0.0159 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner B	Volume of the gaseous fuel combusted	Annual	155,576,471	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	8,414	1	8,414
CH4	0.2	21	3
N2O	0.0	310	5
		TOTAL =	8,422

9,281 TPY CO2

NAME Gasifier Start-up Preheat Burner C

Unit ID: 008 C

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	8760	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0587
$PM_{2.5}$	0.002	0.002	0.0073
SO_2	0.011	0.011	0.0464
NOx	1.800	1.800	7.88
CO	1.008	1.008	4.42
VOC	0.097	0.097	0.43
Total VOC HAPs	0.033	0.033	0.15
Mercury (HAP)	3.0E-05	3.0E-05	1.3E-04

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 8,414 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1587 MT
N2O = 0.0159 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner C	Volume of the gaseous fuel combusted	Annual	155,576,471	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	8,414	1	8,414
CH4	0.2	21	3
N2O	0.0	310	5
		TOTAL =	8,422

9,281 TPY CO2

NAME Gasifier Start-up Preheat Burner D

Unit ID: 008 D

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	8760	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.013	0.013	0.0587
PM$_{2.5}$	0.002	0.002	0.0073
SO$_2$	0.011	0.011	0.0464
NOx	1.800	1.800	7.88
CO	1.008	1.008	4.42
VOC	0.097	0.097	0.43
Total VOC HAPs	0.033	0.033	0.15
Mercury (HAP)	3.0E-05	3.0E-05	1.3E-04

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.026	0.026	0.00038
PM$_{2.5}$	0.024	0.024	0.00035
SO$_2$	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO$_2$
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM$_{10}$	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 8,414 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1587 MT
N2O = 0.0159 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner D	Volume of the gaseous fuel combusted	Annual	155,576,471	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	8,414	1	8,414
CH4	0.2	21	3
N2O	0.0	310	5
		TOTAL =	8,422

9,281 TPY CO2

NAME Gasifier Start-up Preheat Burner E

Unit ID: 008 E

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	8760	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0587
$PM_{2.5}$	0.002	0.002	0.0073
SO_2	0.011	0.011	0.0464
NOx	1.800	1.800	7.88
CO	1.008	1.008	4.42
VOC	0.097	0.097	0.43
Total VOC HAPs	0.033	0.033	0.15
Mercury (HAP)	3.0E-05	3.0E-05	1.3E-04

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 8,414 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1587 MT
N2O = 0.0159 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner E	Volume of the gaseous fuel combusted	Annual	155,576,471	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	8,414	1	8,414		
CH4	0.2	21	3		
N2O	0.0	310	5		
		TOTAL =	8,422	9,281	TPY CO2

NAME Emergency Diesel Power Generator A

Unit ID: 009 A

COMBUSTION DATA

FUEL TYPE	Diesel	
ENGINE SIZE	1,341	HP
HOURS OF OPERATION	500	hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.06	0.06	0.0148
$PM_{2.5}$	0.01	0.01	0.0014
SO_2	0.015	0.015	0.00377
NO_X	14.58	14.58	3.64
CO	0.38	0.38	0.096
VOC (TOC)	0.03	0.03	0.00739

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

	PM_{10}	SO_2	NO_X	CO	VOC
Diesel Industrial Engine Factors (Lb/hp-hr)	4.4E-05	1.1E-05	0.0109	2.9E-04	2.2E-05

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 212.3 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006
1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.00861 MT
N2O = 0.001722 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Emergency Diesel Power Generator A	Gallons of diesel fuel combusted	Annual	20,800	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	212.3	1	212.3
CH4	0.00861	21	0.1808
N2O	0.001722	310	0.534
		TOTAL =	213.0

234.7 TPY CO2

Fuel Consumption 50% load = 20.8 gal/hr.
Assumed Fuel at 100% Load = 41.6 gal/hr.

NAME Emergency Diesel Power Generator B

Unit ID: 009 B

COMBUSTION DATA

FUEL TYPE	Diesel
ENGINE SIZE	1,341 HP
HOURS OF OPERATION	500 hr/yr

EMISSIONS

		avg lb/hr	lb/hr max.	TPY
PM_{10}		0.06	0.06	0.0148
$PM_{2.5}$		0.01	0.01	0.0014
SO_2		0.015	0.015	0.00377
NO_X		14.58	14.58	3.64
CO		0.38	0.38	0.096
VOC	(TOC)	0.03	0.03	0.00739

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

	PM_{10}	SO_2	NO_X	CO	VOC
Diesel Industrial Engine Factors (Lb/hp-hr)	4.4E-05	1.1E-05	0.0109	2.9E-04	2.2E-05

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS

ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 106.1 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.00431 MT
N2O = 0.000861 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Emergency Diesel Power Generator B	Gallons of diesel fuel combusted	Annual	10,400	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	106.1	1	106.1		
CH4	0.00431	21	0.0904		
N2O	0.000861	310	0.267		
		TOTAL =	106.5	117.4	TPY CO2

Fuel Consumption 50% load = 20.8 gal/hr.
Assumed Fuel at 100% Load = 41.6 gal/hr.

NAME	Fire Water Diesel Pump A	Unit ID:	010 A

COMBUSTION DATA

FUEL TYPE	Diesel	
ENGINE SIZE	575	HP
HOURS OF OPERATION	500	hr/yr

EMISSIONS	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0269
$PM_{2.5}$	0.011	0.011	0.0026
SO_2	0.0061	0.0061	0.00152
NO_X	3.131	3.131	0.783
CO	0.799	0.799	0.200
VOC	0.218	0.218	0.0545

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 101 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0041 MT
N2O = 0.00082 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump A	Gallons of diesel fuel combusted	Annual	9,875	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	100.8	1	100.8
CH4	0.00409	21	0.0859
N2O	0.000818	310	0.253
		TOTAL =	101.1

111.4 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

NAME Fire Water Diesel Pump B

Unit ID: 010 B

COMBUSTION DATA

FUEL TYPE	Diesel
ENGINE SIZE	575 HP
HOURS OF OPERATION	500 hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0269
$PM_{2.5}$	0.011	0.011	0.0026
SO_2	0.0061	0.0061	0.00152
NO_X	3.131	3.131	0.783
CO	0.799	0.799	0.200
VOC	0.218	0.218	0.0545

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1\times10^{-3}\times Fuel\times HHV\times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 40 MT

$$CH_4 or N_2O = 1\times10^{-3}\times Fuel\times HHV\times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0016 MT
N2O = 0.00033 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump B	Gallons of diesel fuel combusted	Annual	3,950	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	40.3	1	40.3
CH4	0.00164	21	0.0343
N2O	0.000327	310	0.101
		TOTAL =	40.5

44.6 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

NAME Fire Water Diesel Pump C

Unit ID: 010 C

COMBUSTION DATA

FUEL TYPE	Diesel	
ENGINE SIZE	575	HP
HOURS OF OPERATION	500	hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0269
$PM_{2.5}$	0.011	0.011	0.0026
SO_2	0.0061	0.0061	0.00152
NO_X	3.131	3.131	0.783
CO	0.799	0.799	0.200
VOC	0.218	0.218	0.0545

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 40 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006
1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0016 MT
N2O = 0.00033 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump C	Gallons of diesel fuel combusted	Annual	3,950	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	40.3	1	40.3
CH4	0.00164	21	0.0343
N2O	0.000327	310	0.101
		TOTAL =	40.5

44.6 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

Explanation of PTE Calculation for Material Handling Sources.

The spreadsheets in this workbook present "Uncontrolled" emissions calculations for the feedstock material handling sources (EU-011 and EU-012) of the Indiana Gasification Facility.

Most of these sources are controlled by add-on control devices (fabric filters or wet dust extraction systems). "Controlled" emissions for such sources were separately calculated based on vendor guaranteed control device exit grain loading (gr/acf). However, realistic "uncontrolled emissions" cannot be back-calculated by "undoing" an estimated control efficiency for those devices. Instead, uncontrolled maximum emissions have been calculated in this spreadsheet using AP42 aggregate handling equations from Chapter 13.2.4 - which is the standard methodology for such operations if they were not enclosed and controlled.

Uncontrolled maximum PTE for open sources such as dozer activity and wind erosion which are controlled by wet suppression, are estimated using the uncontrolled lb/hr emissions rate factor presented in the 4/20/11 air permit application Appendix B, pages D2&3, not taking credit for any controls, and assuming 8760 hrs/yr.

Based on the calculations provided, the provisions of 40 CFR Part 64 for Compliance Assurance Monitoring do not apply to these emission units.

UNCONTROLLED PTE OF FEEDSTOCK HANDLING SOURCES

Total PM/PM$_{10}$ EMISSIONS Uncontrolled

Unit ID	Name	Annual Ave Process Rate		Uncontrolled Emission Factor		Operating Hours	PM10 Annual PM10 Emissions TPY	Factor PM Total/ PM10	Total PM Annual Emissions TPY
012 A	Barge Unload to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 B	Barge Unload Hopper to Belt	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 C	Barge Conveyor Transfer Drop	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 D	Barge Conveyor Transfer Drop	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 E	Barge Conveyor Transfer Drop	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 F	Barge Conveyor Transfer Drop	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 G	Rail Unload 1 to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 H	Rail Unload 2 to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 I	Rail Unload Hopper 1 to Belt	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 J	Rail Unload Hopper 2 to Belt	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 K	Rail Unload Belts 1 & 2 to Stacker Belt 1	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 L	Stacker Belt 1 to Radial Stacker (Pile1)	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 M	Stacker Belt 2 from Radial Stacker (Pile 1)	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 N	Radial Stacker to Pile 1	3,000	TPH	0.00056	lb/ton	8,760	7.32	2.114	15.48
012 O	Radial Stacker to Pile 2	3,000	TPH	0.00056	lb/ton	8,760	7.32	2.114	15.48
012 P	Dozer Activity on Pile 1	1,500	TPH	0.798	lb/hr	8,760	3.50	4.58	16.01
012 Q	Dozer Activity on Pile 2	1,500	TPH	0.798	lb/hr	8,760	3.50	4.58	16.01
012 R	Pile 1 / Bottom Hopper / Belt / Classification Tower (assume 3 transfers)	750	TPH	0.00167	lb/ton	8,760	5.49	2.114	11.61
012 S	Pile 1 / Bottom Hopper / Belt / Classification Tower (assume 3 transfers)	750	TPH	0.00167	lb/ton	8,760	5.49	2.114	11.61
012 T	CLASSIFICATION TOWER #1	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 U	CLASSIFICATION TOWER #2	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 V	Classification Towers to Day Bin	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 W	Wind Erosion Pile 1	300,000	Tons	2.157	lb/hr	8,760	9.45	2.0	18.90
012 X	Wind Erosion Pile 2	300,000	Tons	1.794	lb/hr	8,760	7.86	2.0	15.72
012 Y	Transfer tower from Truck/Rail conveyor to	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 Z	Truck Bay 1 dump to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 AA	Truck hopper to conveyor	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 AB	Truck Bay 2 dump to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87
012 AC	Truck Bay 3 dump to Hopper	750	TPH	0.00056	lb/ton	8,760	1.83	2.114	3.87

011 A/B	Process Area Coal-Coke Handling System (assume 3 transfers)	750	TPH	0.002	lb/ton	8,760	5.49	1.0	5.49

Comments:

Dozer activity (012 P and 012 Q) factors calculated based on equations from AP-42 Section 13.2.2
All others based on Transfer point factors calculated based on equations from AP-42 Section 13.2.4
Coke / Coal pile (012 W and 012 X) wind erosion factors calculated based on equations from WRAP documen

PM$_{2.5}$ EMISSIONS Uncontrolled		Annual Ave Process Rate		Uncontrolled Emission Factor		Operating Hours	Annual Emissions
Unit ID	Name						TPY
012 A	Barge Unload to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28
012 B	Barge Unload Hopper to Belt	750	TPH	0.00008	lb/ton	8,760	0.28
012 C	Barge Conveyor Transfer Drop	750	TPH	0.00008	lb/ton	8,760	0.28
012 D	Barge Conveyor Transfer Drop	750	TPH	0.00008	lb/ton	8,760	0.28
012 E	Barge Conveyor Transfer Drop	750	TPH	0.00008	lb/ton	8,760	0.28
012 F	Barge Conveyor Transfer Drop	750	TPH	0.00008	lb/ton	8,760	0.28
012 G	Rail Unload 1 to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28
012 H	Rail Unload 2 to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28
012 I	Rail Unload Hopper 1 to Belt	750	TPH	0.00008	lb/ton	8,760	0.28
012 J	Rail Unload Hopper 2 to Belt	750	TPH	0.00008	lb/ton	8,760	0.28
012 K	Rail Unload Belts 1 & 2 to Stacker Belt 1	750	TPH	0.00008	lb/ton	8,760	0.28
012 L	Stacker Belt 1 to Radial Stacker (Pile1)	750	TPH	0.00008	lb/ton	8,760	0.28
012 M	Stacker Belt 2 from Radial Stacker (Pile 1)	750	TPH	0.00008	lb/ton	8,760	0.28
012 N	Radial Stacker to Pile 1	3,000	TPH	0.00008	lb/ton	8,760	1.11
012 O	Radial Stacker to Pile 2	3,000	TPH	0.00008	lb/ton	8,760	1.11
012 P	Dozer Activity on Pile 1	1,500	TPH	0.080	lb/hr	8,760	0.35
012 Q	Dozer Activity on Pile 2	1,500	TPH	0.080	lb/hr	8,760	0.35
012 R	Pile 1 / Bottom Hopper / Belt / Classification Tower (assume 3 transfers)	750	TPH	0.00025	lb/ton	8,760	0.83
012 S	Pile 1 / Bottom Hopper / Belt / Classification Tower (assume 3 transfers)	750	TPH	0.00025	lb/ton	8,760	0.83
012 T	CLASSIFICATION TOWER #1	750	TPH	0.00008	lb/ton	8,760	0.28
012 U	CLASSIFICATION TOWER #2	750	TPH	0.00008	lb/ton	8,760	0.28
012 V	Classification Towers to Day Bin	750	TPH	0.00008	lb/ton	8,760	0.28
012 W	Wind Erosion Pile 1	300,000	tons	0.229	lb/hr	8,760	1.00
012 X	Wind Erosion Pile 2	300,000	Tons	0.190	lb/hr	8,760	0.83
012 Y	Transfer tower from Truck/Rail conveyor to	750	TPH	0.00008	lb/ton	8,760	0.28
012 Z	Truck Bay 1 dump to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28
012 AA	Truck hopper to conveyor	750	TPH	0.00008	lb/ton	8,760	0.28
012 AB	Truck Bay 2 dump to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28
012 AC	Truck Bay 3 dump to Hopper	750	TPH	0.00008	lb/ton	8,760	0.28

011 A/B	Process Area Coal-Coke Handling System (conservatively assume 7 transfers steps)	750	TPH	0.00059	lb/ton	8,760	1.94

Comments:

Dozer activity (012 P and 012 Q) factors calculated based on equations from AP-42 Section 13.2.2
All others based on Transfer point factors calculated based on equations from AP-42 Section 13.2.4
Coke / Coal pile (012 W and 012 X) wind erosion factors calculated based on equations from WRAP documen

CALCULATION SHEET

Emission Unit	**Emission Description**
Each Material Handling Step	Handling (Drop) emissions for handling/loading - if done so without controls

Calculation Methodology

AP-42 Chapter 13, Section 2.4:Aggregate Handling and Storage Piles
Uncontrolled Emissions per handling step calculated using equation (1)

$$E = k\left(0.0032\right)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

$$E = k\left(0.0032\right)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where:
E = emissions factor in lbs emissions per ton aggregate handled
U = mean wind speed, mph
M = material moisture content
k = particle size multplier (dimensionless)
Total PM k=0.74
PM10 k=0.35
PM2.5 k=0.053

Calculation of Potential Emissions:

Number of Drops(handling steps)	1.000	drops
Mean wind speed	7.0	mph
Material Moisture content	4.50	%
Particle Size Multiplier, k:	0.35	PM10
Particle Size Multiplier, k:	0.053	PM2.5
Particle Size Multiplier, k:	0.74	Total PM

Max. Annual Feedstock Usage:	10,401.0	tons/day
Nominal Capacity	750	tons/hr
Hours per yr of activity	8760.0	hr/yr
Control Efficiency	Not included in this pre-control PTE calc.	

Potential PM10 Emissions:

	EF lb/ton	tpy
Each Material Handling Step	0.00056	1.8309

Potential PM2.5 Emisions:

	EF lb/ton	tpy
Each Material Handling Step	0.00008	0.2773

Potential Total PM Emisions:

	EF lb/ton	tpy
Each Material Handling Step	0.00118	3.8710

total PM/PM10 ratio
2.11429

Uncontrolled Emissions Factors for open material handling sources

		Total PM	PM10	PM2.5
Dozer Activity (each pile)	lb/hr	3.65484	0.798	0.08
Wind Erosion Pile 1	lb/hr	4.314	2.157	0.229
Wind Erosion Pile 2	lb/hr	3.588	1.794	0.19

Above factors for PM10 and PM2.5 from page D2 and D3 of Appendix B of air permit application submitted 4/20/11.

Factor for total PM is based on PM10 factor times 2.114 for dozer, and 2.0 for wind erosion. These factors based on ratio of particle size multipler factors from AP42 13.2.2 for the dozer and the WRAP document for Wind Erosion.

NAME Rod Mill Air Eductors

STACK DATA

HEIGHT	125	ft
DIAMETER	0.5	ft
GAS EXIT TEMP	80	°F
GAS EXIT VELOCITY	15.46	fps
OPERATING HOURS	8,760	hr/yr

PM_{10} EMISSIONS	Average Emissions	Maximum Hourly	Annual PM_{10} Emissions	Annual $PM_{2.5}$ Emissions
Unit ID	lb/hr	lb/hr	TPY	TPY
013 A	0.025	0.025	0.11	0.032
013 C	0.025	0.025	0.11	0.032
013 C	0.025	0.025	0.11	0.032
013 D	0.025	0.025	0.11	0.032
Total	0.10	0.10	0.44	0.13

Emissions based on engineered equipment data

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

VENT SOURCES

NAME Wet Sulfuric Acid (WSA) Unit Stack A Unit ID: 015 A

Emissions of all pollutants are higher for the Coal / Coke Case.

STACK DATA

HEIGHT	200	ft
DIAMETER	4.83	ft
GAS EXIT TEMP	176	°F
GAS EXIT VELOCITY: Two Unit Operation	102.2	fps
GAS EXIT VELOCITY: One Unit Operation	51.1	fps
GAS EXIT VELOCITY: Black start	25.5	fps
GAS EXIT VELOCITY: Preheat	115.3	fps

COMBUSTION DATA

HEAT INPUT - Preheat	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
OPERATING HOURS: Two Unit Operation	8,760	hr/yr
OPERATING HOURS: One Unit Operation	0	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
OPERATING HOURS: Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	36.35
NOx	10.17	10.17	44.55
CO	18.72	18.72	82.01
H_2SO_4	5.00	5.00	21.88
Mercury (HAP)	3.3E-10	3.3E-10	1.5E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.00
NOx	5.09	5.09	0.00
CO	9.36	9.36	0.00
H_2SO_4	2.50	2.50	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
$PM_{2.5}$	0.02	0.02	0.0006
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.00018	0.03	0.0008
$PM_{2.5}$	0.00015	0.02	0.0006
SO_2	8.31	8.30	36.38
NOx	10.21	10.17	44.70
CO	18.75	18.72	82.13
VOC	0.0013	0.19	0.006
Total VOC HAPs	0.0004	0.06	0.0019
Mercury (HAP)	4.0E-07	6.5E-02	1.8E-06
H_2SO_4	5.00	5.00	21.90
$PM_{2.5}$ including H_2SO_4	5.00	5.00	21.90

CALCULATIONS
Emissions Preheat Case: (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions Preheat Case: (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

Source: Emission factors for NOx and CO are based on information from vendor supplied data.

Comments:

SO2 emissions for preheat case based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.
The emission rate data from the WSA Trains is based on information from process licensee.
Total WSA capacity for two trains is 136,658 lb/h of 97.5 wt% Sulfuric Acid production OR 1,599 stpd on dry basis (100% acid).
Burner flue gas is scrubbed in gasifier quench water to remove over 90% of particulate.

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Coal / Coke Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,760	hr/yr
Half Rate	0	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	36.35
NOx	10.17	10.17	44.55
CO	18.72	18.72	82.01
H_2SO_4	5.00	5.00	21.88
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.00
NOx	5.09	5.09	0.00
CO	9.36	9.36	0.00
H_2SO_4	2.50	2.50	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	3.9E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal-Coke)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	14538.1	lb-mole/hr		
CO2% =	6.60%			
CO2 MW =	44.01	lb/lb-mole		
CO2 Emissions =	42,209	lb/hr	185,003	TPY CO2
			15%	Contingency due to lack of performance guarantee
			212,999	TPY CO2

Coal Only Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,760	hr/yr
Half Rate	0	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	7.57	7.57	33.15
NOx	7.40	7.40	32.43
CO	13.63	13.63	59.69
H_2SO_4	3.64	3.64	15.93
Mercury (HAP)	3.3E-10	3.3E-10	1.5E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	3.78	3.78	0.00
NOx	3.70	3.70	0.00
CO	6.81	6.81	0.00
H_2SO_4	1.82	1.82	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	1.89	1.89	0.02
NOx	1.85	1.85	0.02
CO	3.41	3.41	0.04
H_2SO_4	0.91	0.91	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.6E-05	5.6E-05	1.7E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust = 10393.9 lb-mole/hr
CO2% = 10.262%
CO2 MW = 44.01 lb/lb-mole
CO2 Emissions = 46,941 lb/hr 205,743 TPY CO2
15% Contingency due to lack of performance guarantee
236,877 TPY CO2

VENT SOURCES

NAME Wet Sulfuric Acid (WSA) Unit Stack B

Unit ID: 015 B

Emissions of all pollutants are higher for the Coal / Coke Case.

STACK DATA

HEIGHT	200	ft
DIAMETER	4.83	ft
GAS EXIT TEMP	176	°F
GAS EXIT VELOCITY: Two Unit Operation	102.2	fps
GAS EXIT VELOCITY: One Unit Operation	51.1	fps
GAS EXIT VELOCITY: Black start	25.5	fps
GAS EXIT VELOCITY: Preheat	115.3	fps

COMBUSTION DATA

HEAT INPUT - Preheat	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
OPERATING HOURS: Two Unit Operation	8,760	hr/yr
OPERATING HOURS: One Unit Operation	0	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
OPERATING HOURS: Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	36.35
NOx	10.17	10.17	44.55
CO	18.72	18.72	82.01
H_2SO_4	5.00	5.00	21.88
Mercury (HAP)	3.3E-10	3.3E-10	1.5E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.00
NOx	5.09	5.09	0.00
CO	9.36	9.36	0.00
H_2SO_4	2.50	2.50	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
$PM_{2.5}$	0.02	0.02	0.0006
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.00018	0.03	0.0008
$PM_{2.5}$	0.00015	0.02	0.0006
SO_2	8.31	8.30	36.38
NOx	10.21	10.17	44.70
CO	18.75	18.72	82.13
VOC	0.0013	0.19	0.006
Total VOC HAPs	0.0004	0.06	0.0019
Mercury (HAP)	4.0E-07	6.5E-02	1.8E-06
H_2SO_4	5.00	5.00	21.90
$PM_{2.5}$ including H_2SO_4	5.00	5.00	21.90

CALCULATIONS

Emissions Preheat Case: (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions Preheat Case: (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)

Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

Source: Emission factors for NOx and CO are based on information from vendor supplied data.

Comments:

SO2 emissions for preheat case based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

The emission rate data from the WSA Trains is based on information from process licensee.

Total WSA capacity for two trains is 136,658 lb/h of 97.5 wt% Sulfuric Acid production OR 1,599 stpd on dry basis (100% acid).

Burner flue gas is scrubbed in gasifier quench water to remove over 90% of particulate.

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Coal / Coke Case

	35.00 MM Btu/hr
	1,020 Btu/ft^3
Full Rate	8,760 hr/yr
Half Rate	0 hr/yr
Black Start	24 hr/yr
Preheat	60 hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	36.35
NOx	10.17	10.17	44.55
CO	18.72	18.72	82.01
H_2SO_4	5.00	5.00	21.88
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.00
NOx	5.09	5.09	0.00
CO	9.36	9.36	0.00
H_2SO_4	2.50	2.50	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	3.9E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.00078
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal-Coke)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per m 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust = 14538.1 lb-mole/hr
CO2% = 6.60%
CO2 MW = 44.01 lb/lb-mole
CO2 Emissions = 42,209 lb/hr 185,003 TPY CO2
15% Contingency due to lack of performance guarantee
212,999 TPY CO2

Coal Only Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,760	hr/yr
Half Rate	0	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	7.57	7.57	33.15
NOx	7.40	7.40	32.43
CO	13.63	13.63	59.69
H_2SO_4	3.64	3.64	15.93
Mercury (HAP)	3.3E-10	3.3E-10	1.5E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	3.78	3.78	0.00
NOx	3.70	3.70	0.00
CO	6.81	6.81	0.00
H_2SO_4	1.82	1.82	0.00
Mercury (HAP)	3.3E-10	3.3E-10	0.0E+00

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	1.89	1.89	0.02
NOx	1.85	1.85	0.02
CO	3.41	3.41	0.04
H_2SO_4	0.91	0.91	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.00078
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.6E-05	5.6E-05	1.7E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mr 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	10393.9	lb-mole/hr
CO2% =	10.262%	
CO2 MW =	44.01	lb/lb-mole
CO2 Emissions =	46,941	lb/hr

205,743 TPY CO2
15% Contingency due to lack of performance guarantee
236,877 TPY CO2

COOLING TOWER

NAME ASU Cooling Water Tower CAP

Unit ID: 016a

Evaporative Cooler Operating Parameters				Emissions		Emissions	
Flow Rate, (gpm)	Drift Rate, %	Drift lb/hr	TDS (ppm)	PM lb/hr	PM TPY	PM2.5 lb/hr	PM2.5 TPY
54,956	0.0005	138	1,500	0.21	0.90	0.16	0.70

Comments:

The ASU Cooling Water Tower consists of 6 individual cells, which are being capped under EIQ No. 16a. The total water flow rate cannot exceed the CAP value, regardless of the number of cells in operation. Therefore, the emissions listed above are the capped total lb/hr and TPY.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Drift rate guaranteed by vendor.

Assume all dissolved solids to be PM$_{10}$. PM2.5 assumed to be 78% of total PM

Total Spray flow provided by B&V.

COOLING TOWER

NAME Main Cooling Water Tower CAP

Unit ID: 016b

Evaporative Cooler Operating Parameters				Emissions		Emissions	
Flow Rate, (gpm)	Drift Rate, %	Drift lb/hr	TDS (ppm)	PM10 lb/hr	PM10 TPY	PM2.5 lb/hr	PM2.5 TPY
404,676	0.0005	1,013	1,500	1.52	6.65	1.18	5.19

Comments:

The Main Cooling Water Tower consists of 24 individual cells, which are being capped under EIQ No. 16b. The total water flow rate cannot exceed the CAP value, regardless of the number of cells in operation. Therefore, the emissions listed above are the capped total lb/hr and TPY.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Drift rate guaranteed by vendor.

Assume all dissolved solids to be PM_{10}. PM2.5 assumed to be 78% of total PM

Total flow provided by B&V.

NAME ASU Molecular Sieve Regeneration Vents

The molecular sieves are regenerated by blowing nitrogen through them.

STACK DATA

HEIGHT	60	ft
DIAMETER	8	ft
GAS EXIT TEMP	260	°F
GAS EXIT VELOCITY	62.02	fps
OPERATING HOURS (each)	8,760	hr/yr

PM_{10} EMISSIONS	Average Emissions	Maximum Hourly	Annual PM_{10} Emissions	Annual $PM_{2.5}$ Emissions
Unit ID	lb/hr	lb/hr	TPY	TPY
017 A	0.13	0.13	0.55	0.039
017 B	0.13	0.13	0.55	0.039
Total	0.25	0.25	1.10	0.077

Regeneration occurs for 1 hr out of every 5 hr for each molecular sieve.
The vent stream is primarily nitrogen (>98%), with a trace amount of particulates.
Emissions based on engineered equipment data
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM10] (Calc for each pile)

TYPES OF TRUCKS	AVERAGE* TRUCK WEIGHT TONS	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	UNPAVED PRECIPITATION CORRECTION	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	Trucks Trips per day	Trucks Trips per hour
COAL PILE DOZER OPERATIONS	41.38	1.061	0.68	0.73	155	12.9

ASSUMPTIONS		
CAT 824H Wheel Dozer	**lbs**	**Tons**
Estimate Total Capacity	**100,195**	**50.10**
Tare	**65,325**	**32.66**
Estimate Capacity	**34,870**	**17.44**
Average Equipment Weight	**82,760**	**41.38**
Maximum Feedstock moved each hr (12hr/day)	**450,000**	**225.00**
Maximum Number of Trips per Hour	**12.9**	

Unpaved Road Equation is based on speeds of 15-45 mph.
Based on the speed of the dozer - 3 - 8 mph, an overall 95% control efficiency is possible.
Wet suppression is used for additional control.

A 90% control efficiency is being conservatively used.

Average daily dozer travel distance each trip assumed to be 1/2 pile radius times two (for round trip).

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM10] (Calc. for each pile)

MILES ROUND TRIP PAVED	**MILES ROUND TRIP UNPAVED each trip**	**ON-SITE VMT/DAY UNPAVED**	**UNCONTROLLED EMISSIONS LBS/DAY**	**PERCENT CONTROL**	**CONTROLLED EMISSIONS LBS/DAY**	Ave Daily **CONTROLLED EMISSIONS LBS/HR***	**CONTROLLED EMISSIONS Tons/yr**
0	0.05105	7.91	5.7	90%	0.5747	0.0239	0.1049

UNPAVED ROADS EQUATIONS

$$E = k * \left(s/12 \right)^a * \left(W/3 \right)^b$$

$$E_{ext} = E \left(\frac{365 - P}{365} \right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Coal Trucks = 50 tons, Ash Trucks = 50 tons, Limestone Trucks = 25 tons

Eext = natural mitigation emission factor (lb/VMT)
P = number of days per year with 0.01 in or more of precipitation

INPUTS

k	1.5	lb/VMT		P	115	wet days/yr
s	2.2	%	AP-42 13.2.4-1			
a	0.9					
b	0.45					
P	115	days				

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM2.5] (each pile)

TYPES OF TRUCKS	AVERAGE* TRUCK WEIGHT TONS	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	UNPAVED PRECIPITATION CORRECTION	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	Trucks Trips per day	Trucks Trips per hour
COAL PILE DOZER OPERATIONS	41.38	0.106	0.68	0.07	155	12.9

ASSUMPTIONS

CAT 824H Wheel Dozer	**lbs**	**Tons**
Estimate Total Capacity	**100,195**	**50.10**
Tare	**65,325**	**32.66**
Estimate Capacity	**34,870**	**17.44**
Average Equipment Weight	**82,760**	**41.38**
Maximum Feedstock moved each hr (12hr/day)	**450,000**	**225.0**
Maximum Number of Trips per Hour	**12.9**	

Unpaved Road Equation is based on speeds of 15-45 mph.
Based on the speed of the dozer - 3 - 8 mph, an overall 95% control efficiency is reasonable.

Average daily dozer travel distance each trip assumed to be 1/2 pile radius times two (for round trip).

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM2.5] (each pile)

MILES ROUND TRIP PAVED	**MILES ROUND TRIP UNPAVED* each trip**	**ON-SITE VMT/DAY UNPAVED**	**UNCONTROLLED EMISSIONS LBS/DAY**	**PERCENT CONTROL**	**CONTROLLED EMISSIONS LBS/DAY**	Ave Daily **CONTROLLED EMISSIONS LBS/HR***	**CONTROLLED EMISSIONS Tons/yr**
0	0.05105	7.9	0.57	90%	0.0575	0.0024	0.0105

UNPAVED ROADS EQUATIONS

$$E = k * \left(\frac{s}{12}\right)^{a} * \left(\frac{W}{3}\right)^{b}$$

$$E_{ext} = E\left(\frac{365 - P}{365}\right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Coal Trucks = 50 tons, Ash Trucks = 50 tons, Limestone Trucks = 25 tons

Eext = natural mitigation emission factor (lb/VMT)
P = number of days per year with 0.01 in or more of precipitation

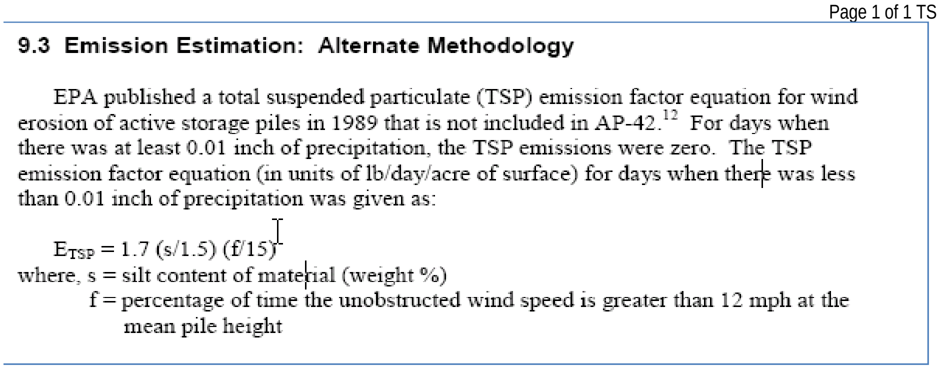
INPUTS

k	0.15	lb/VMT	
s	2.2	%	AP-42 13.2.4-1
a	0.9		
b	0.45		
P	115	days	

P	115	wet days/yr

Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

Basis: Wrap Fugitive Dust Handbook, Prepared for Governers Conference, Western Regional Air Partnership (WRAP) Methodology for wind erosion.



9.3 Emission Estimation: Alternate Methodology

EPA published a total suspended particulate (TSP) emission factor equation for wind erosion of active storage piles in 1989 that is not included in AP-42.[12] For days when there was at least 0.01 inch of precipitation, the TSP emissions were zero. The TSP emission factor equation (in units of lb/day/acre of surface) for days when there was less than 0.01 inch of precipitation was given as:

$E_{TSP} = 1.7\ (s/1.5)\ (f/15)$

where, s = silt content of material (weight %)

f = percentage of time the unobstructed wind speed is greater than 12 mph at the mean pile height

Referened document can be obtained at:
http://www.wrapair.org/forums/dejf/fdh/content/Ch9-Storage_Pile_Wind%20Erosion_Rev06.pdf

WRAP document basis for equation is stated to be from 1989 EPA document:
USEPA, January 1989. Air/Superfund National Technical Guidance Study Series; Volume III – Estimation of Air Emissions from Cleanup Activities at Superfund Sites, Interim final report EPA-450/1-89-003.

Assumptions

	Data	Descript.	Basis
silt	2.20	% (s) Silt content	AP-42 13.2.4-1, Coal as received, coal power plant. Also used for coke (coke should be lower).
% windy	100.00	% (f) % high wind	Conservatively assume high winds on worse case day.
PM10 Multiplier	0.5	ratio PM10 vs TSP	
PM2.5 Multiplier	0.053	ratio PM2.5 vs TSP	
Control effective.	90%	Watering and compaction / BACT	
Pile size coal	6.230	acres (see attached Surf. Area Calcs.)	
Pile size coke	5.180	acres (see attached Surf. Area Calcs.)	

Calculated Emiss. Factors from above Equation

Uncontrolled Emissions Factors

TSP	16.62	lb/day/acre of surface
PM10	8.31	lb/day/acre of surface
PM2.5	0.881	lb/day/acre of surface

Controlled Emissions Factors

PM10	0.83	lb/day/acre of surface
PM2.5	0.088	lb/day/acre of surface

Calculated Emissions Rate

Controlled Emissions Rate - lb/hr worse case day
*(= Controlled factor * acres / 24hr/day)*

Coal Pile			***Coke Pile***		
PM10	**0.216**	**lb PM10/hr**	**PM10**	**0.179**	**lb PM10/hr**
PM2.5	**0.023**	**lb PM2.5/hr**	**PM2.5**	**0.019**	**lb PM2.5/hr**

Annual Emissons - conservatively assuming max rate on all days.

PM10	**0.94**	**TPY PM10**	**PM10**	**0.79**	**TPY PM10**
PM2.5	**0.10**	**TPY PM2.5**	**PM2.5**	**0.08**	**TPY PM2.5**

Note: the above method is used for calculating emissions for air modeling purposes in preference to AP42 section 13.2.5 because, as stated in AP42 section 13.2.5, page 13.2.5-3, regarding its wind erosion formula:
". . .Calculated emissions represent intermittent events and should not be input directly into dispersion models that assume steady-state emission rates. "

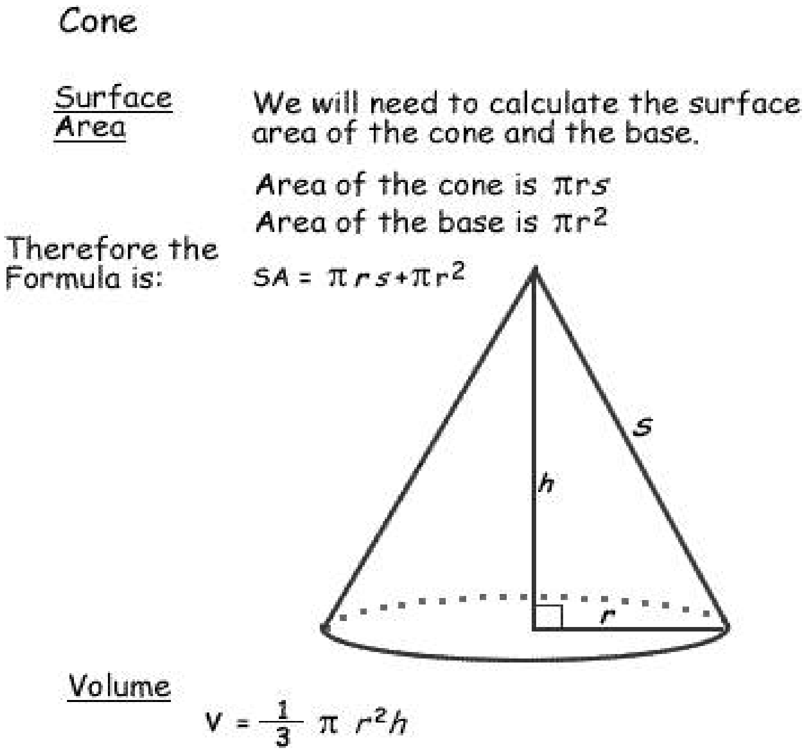
Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

6.23 acres
coal pile surface area = 271,379 ft^2
top height = 203
top diameter = 150
top slant = 135.62 √[(top height - pile height)^2+(top diameter/2)^2]
pile height = 90
pile diameter = 539
pile slant = 337.40 √[(top height)^2+(pile diameter/2)^2]

Surface area truncated cone = SA of whole cone - SA of top/removed cone + area of top.

$$\boxed{SA = \pi * r_p * s_p - \pi * r_t * s_t + \pi * r_t^2}$$

5.18 acres
coke pile surface area = 225,647 ft^2
top height = 186
top diameter = 150
top slant = 135.62 √[(top height - pile height)^2+(top diameter/2)^2]
pile height = 73
pile diameter = 494
pile slant = 309.20 √[(top height)^2+(pile diameter/2)^2]



Cone

Surface Area

We will need to calculate the surface area of the cone and the base.

Area of the cone is $\pi r s$

Area of the base is πr^2

Therefore the Formula is:

$SA = \pi r s + \pi r^2$

Volume

$V = \frac{1}{3} \pi r^2 h$

AGRICO STACKER STORAGE PILE CAPACITY

Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

	Coke x 1	100% coal	85% coal	51% coal	
BOOM REACH	**135.00**	**150.00**	**150.00**	**150.00**	FT
ANGLE OF REPOSE	**37.00**	**37.00**	**37.00**	**37.00**	DEGREES
PILE HEIGHT	**73.00**	**90.00**	**90.00**	**90.00**	FT
TOWER RADIUS	**20.00**	**20.00**	**20.00**	**20.00**	FT
TANGENT	0.75	0.75	0.75	0.75	
OUTSIDE CONE RADIUS	231.87	269.43	269.43	269.43	FT
OUTSIDE PILE DIAMETER	463.74	538.85	538.85	538.85	FT
PI*R*R	168,901.00	228,051.00	228,051.00	228,051.00	SQ FT
HEIGHT OF TOTAL CONE	174.74	203.04	203.04	203.04	FT
TOTAL CONE CAPACITY	9,837,695.00	15,434,491.70	15,434,491.70	15,434,491.70	CU FT
TOP CONE RADIUS	135.00	150.00	150.00	150.00	FT
PI*R*R	57,255.50	70,685.80	70,685.80	70,685.80	
HEIGHT OF TOP CONE	101.74	113.04	113.04	113.04	FT
TOP CONE CAPACITY	1,941,649.00	2,663,441.00	2,663,441.00	2,663,441.00	CU FT
INSIDE TOWER	1,257.00	1,257.00	1,257.00	1,257.00	SQ FT
LOSS CAPACITY - TOWER	91,761.00	113,130.00	113,130.00	113,130.00	CU FT
NET CAPACITY	7,804,285.00	12,657,920.70	12,657,920.70	12,657,920.70	CU FT
MAT'L DENSITY	**47.00**	**50.00**	**50.00**	**50.00**	LB/CU FT
NET CAPACITY	366,801,395.00	632,896,035.00	632,896,035.00	632,896,035.00	LBS
	2,000.00	2,000.00	2,000.00	2,000.00	LBS/TON
NET CAPACITY	183,400.70	316,448.00	316,448.00	316,448.00	TONS
AREA OF PILE	168,901.25	228,050.64	228,050.64	228,050.64	SQ FT
AREA OF PILE	3.88	5.24	5.24	5.24	ACRES
DAYS STORAGE	44.87	33.08	38.92	64.86	DAYS each
Coal Consumption (100% fuel)		9,565.00	8,131.10	4,878.66	tpd
Coke Consumption (49% fuel)	4,087.00				tpd

	%	Tons	Days storage
Coke	49%	4,087.00	44.87
Coal	51%	4,878.15	64.87
	85%	8,130.25	38.92
	100%	9,565.00	33.08

COMBUSTION SOURCES

NAME ZLD Spray Dryer Stack

Unit ID: 032

STACK DATA

HEIGHT	100	ft
DIAMETER	1	ft
GAS EXIT TEMP	310	°F
GAS EXIT VELOCITY	35.49	fps

COMBUSTION DATA

HEAT INPUT	5.6	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
PROCESS FLOW RATE	2,735	dscfm
OPERATING HOURS	8,760	hr/yr

EMISSIONS:

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.12	0.12	0.51
$PM_{2.5}$	0.11	0.11	0.48
SO_2	0.003	0.003	0.015
NOx	0.197	0.197	0.86
CO	0.203	0.203	0.89
VOC	0.030	0.030	0.13
Total VOC HAPs	0.010	0.010	0.046
Mercury (HAP)	9.4E-06	9.4E-06	4.1E-05

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)

Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.60

Fabric Filter	PM_{10}
Factor (gr/dscf)	0.0050

Natural Gas Combustion	NOx	CO	VOC
Factor (lb/MM Btu)	0.035	0.036	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).

Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).

Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 2,616 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0493 MT
N2O = 0.0049 MT

Emission Points	Data Required	MRR Frequency	Data	Units
ZLD Spray Dryer Stack	Volume of the gaseous fuel combusted	Annual	48,379,046	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	2,616	1	2,616
CH4	0.049	21	1
N2O	0.0049	310	2
		TOTAL =	2,619

2,886 TPY CO2

NAME ZLD Inert Gas Vent

Unit ID: 033

Mercury is controlled using a sulfided carbon adsorbent with a vendor guarantee of 0.5 ppbv.

STACK DATA

HEIGHT	15	ft
DIAMETER	0.083	ft
GAS EXIT TEMP	150	°F
GAS EXIT VELOCITY	31.74	fps
OPERATING HOURS	8,760	hr/yr

EMISSIONS	Average Emissions	Maximum Hourly	Average Annual Emissions	Average Annual Emissions
	lb/hr	lb/hr	lb/yr	TPY
Carbon Dioxide	46.50	46.50	407,340	203.7
Mercury	1.40E-07	0.0149	0.7168	< 0.001

Assumptions:

Vent stream is 75.5% CO2 and 24.5% H20.

Mercury in solids feed to Gasifier at max is 0.745 lb/hr

Gasification process wastewater picks up 2% of the mercury in the gasifiers, resulting in 0.0149 lb/hr mercury in the water, all of which goes to the ZLD inert gas vent.

Sulfided carbon adsorbent control is >99.99% effective, but is offline up to 2 days/year for carbon changeout.

Basis of Total HAP Emission Factor for Natural Gas Combustion

Project: Indiana Gasification

Emissions Estimation

AP-42 Heating Value 1,020 Btu/scf

EMISSION FACTOR BASED INVENTORY		**AP-42 Em. Factor**			**Notes**
POLLUTANT	**CAS #**	**Em.Fac. Source**	**lb/MMscf**	**lb/MMBtu**	
2-Methylnaphthalene	91-57-6	AP-42, Table 1.4-3	2.40E-05	2.35E-08	b
3-Methylchloranthrene	56-49-5	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b
7,12-Dimethylbenz(a)anthracene	---	AP-42, Table 1.4-3	1.60E-05	1.57E-08	b, c
Acenaphthene	83-32-9	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Acenaphthylene	203-96-8	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Anthracene	120-12-7	AP-42, Table 1.4-3	2.40E-06	2.35E-09	b, c
Benz(a)anthracene	56-55-3	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Benzene	71-43-2	AP-42, Table 1.4-3	2.10E-03	2.06E-06	b
Benzo(a)pyrene	50-32-8	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Benzo(b)fluoranthene	205-99-2	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Benzo(g,h,i)perylene	191-24-2	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Benzo(k)fluoranthene	205-82-3	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Chrysene	218-01-9	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Dibenzo(a,h)anthracene	53-70-3	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Dichlorobenzene	25321-22-6	AP-42, Table 1.4-3	1.20E-03	1.18E-06	b
Fluoranthene	206-44-0	AP-42, Table 1.4-3	3.00E-06	2.94E-09	b, c
Fluorene	86-73-7	AP-42, Table 1.4-3	2.80E-06	2.75E-09	b, c
Formaldehyde	50-00-0	AP-42, Table 1.4-3	7.50E-02	7.35E-05	b
Hexane	110-54-3	AP-42, Table 1.4-3	1.80E+00	1.76E-03	b
Indeno(1,2,3-cd)pyrene	193-39-5	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Naphthalene	91-20-3	AP-42, Table 1.4-3	6.10E-04	5.98E-07	b
Phenanathrene	85-01-8	AP-42, Table 1.4-3	1.70E-05	1.67E-08	b, c
Pyrene	129-00-0	AP-42, Table 1.4-3	5.00E-06	4.90E-09	b, c
Toluene	108-88-3	AP-42, Table 1.4-3	3.40E-03	3.33E-06	b
Arsenic	7440-38-2	AP-42, Table 1.4-4	2.00E-04	1.96E-07	b
Beryllium	7440-41-7	AP-42, Table 1.4-4	1.20E-05	1.18E-08	b
Cadmium	7440-43-9	AP-42, Table 1.4-4	1.10E-03	1.08E-06	b
Chromium	7440-47-3	AP-42, Table 1.4-4	1.40E-03	1.37E-06	b
Cobalt	7440-48-4	AP-42, Table 1.4-4	8.40E-05	8.24E-08	b
Manganese	7439-96-5	AP-42, Table 1.4-4	3.80E-04	3.73E-07	b
Mercury	7439-97-6	AP-42, Table 1.4-4	2.60E-04	2.55E-07	b
Nickel	7440-02-0	AP-42, Table 1.4-4	2.10E-03	2.06E-06	b
Selenium	7782-49-2	AP-42, Table 1.4-4	2.40E-05	2.35E-08	b
		Total HAP =	1.88796	0.00185	

Notes:

a. Criteria pollutant by name or association, i.e., VOC as surrogates for O3

b. Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

c. HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of Clean Air Act

d. non-VOC per 40 CFR 51.100(s)(1); methane and ethane are not considered as regulated photochemical reactive VOC

e. Soot in concentration values, 0 micrograms per liter (ug/L); lightly smoking flares, 40 ug/L; average smoking flares, 177 ug/L; and heavily smoking flares 274 ug/L.

f. To be used where source testing or fuel analysis are not required by the AB2588 Criteria and Guidelines Regulations, Appendix D

g. Based on 100% conversion of fuel sulfur to SO2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

		lb/hr (per individual emission unit, maximum short term)												
EMISSION FACTOR BASED INVENTORY		**001**	**002**	**005**	**007**	**008**	**015**	**024**	**025**	**029**	**030**	**032**	**FUG**	
Number of emission units		1	1	2	2	5	2	1	1	1	1	1	1	**Notes**
POLLUTANT	**CAS #**	**0.27**	**0.27**	**408.17**	**38.81**	**35.00**	**35.00**	**-**	**-**	**-**	**-**	**5.63**	**-**	**MMBtu/hr**
2-Methylnaphthalene	91-57-6	6.24E-09	6.24E-09	9.60E-06	9.13E-07	4.12E-06	8.24E-07	-	-	-	-	1.33E-07	-	b
3-Methylchloranthrene	56-49-5	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b
7,12-Dimethylbenz(a)anthracene	---	4.16E-09	4.16E-09	6.40E-06	6.09E-07	2.75E-06	5.49E-07	-	-	-	-	8.84E-08	-	b, c
Acenaphthene	83-32-9	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Acenaphthylene	203-96-8	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Anthracene	120-12-7	6.24E-10	6.24E-10	9.60E-07	9.13E-08	4.12E-07	8.24E-08	-	-	2.88E-07	-	1.33E-08	-	b, c
Arsenic	7440-38-2	5.20E-08	5.20E-08	8.00E-05	7.61E-06	3.43E-05	6.86E-06	-	-	-	-	1.10E-06	-	b
Benz(a)anthracene	56-55-3	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Benzene	71-43-2	5.46E-07	5.46E-07	8.40E-04	7.99E-05	3.60E-04	7.21E-05	-	-	1.08E-03	5.59E-05	1.16E-05	-	b
Benzo(a)pyrene	50-32-8	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Benzo(b)fluoranthene	205-99-2	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Benzo(g,h,i)perylene	191-24-2	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Benzo(k)fluoranthene	205-82-3	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Beryllium	7440-41-7	3.12E-09	3.12E-09	4.80E-06	4.57E-07	2.06E-06	4.12E-07	-	-	-	-	6.63E-08	-	b
Biphenyl	92-52-4	-	-	-	-	-	-	-	-	3.18E-06	-	-	-	b,c
Cadmium	7440-43-9	2.86E-07	2.86E-07	4.40E-04	4.19E-05	1.89E-04	3.77E-05	-	-	-	-	6.07E-06	-	b
Carbonyl Sulfide	463-58-1	6.67E-02	-	-	7.80E-02	-	-	-	-	-	-	-	2.82E-03	b
Chromium	7440-47-3	3.64E-07	3.64E-07	5.60E-04	5.33E-05	2.40E-04	4.80E-05	-	-	-	-	7.73E-06	-	b
Chrysene	218-01-9	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Cobalt	7440-48-4	2.18E-08	2.18E-08	3.36E-05	3.20E-06	1.44E-05	2.88E-06	-	-	-	-	4.64E-07	-	b
Cumene	98-82-8	-	-	-	-	-	-	-	-	-	4.65E-06	-	-	b
Dibenzo(a,h)anthracene	53-70-3	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Dichlorobenzene	25321-22-6	3.12E-07	3.12E-07	4.80E-04	4.57E-05	2.06E-04	4.12E-05	-	-	-	-	6.63E-06	-	b
Ethylbenzne	100-41-4	-	-	-	-	-	-	-	-	5.37E-03	2.07E-05	-	-	b
Fluoranthene	206-44-0	7.80E-10	7.80E-10	1.20E-06	1.14E-07	5.15E-07	1.03E-07	-	-	-	-	1.66E-08	-	b, c
Fluorene	86-73-7	7.28E-10	7.28E-10	1.12E-06	1.07E-07	4.80E-07	9.61E-08	-	-	-	-	1.55E-08	-	b, c
Formaldehyde	50-00-0	1.95E-05	1.95E-05	3.00E-02	2.85E-03	1.29E-02	2.57E-03	-	-	-	-	4.14E-04	-	b
Hexane	110-54-3	4.68E-04	4.68E-04	7.20E-01	6.85E-02	3.09E-01	6.18E-02	-	-	-	5.42E-04	9.94E-03	-	b
Indeno(1,2,3-cd)pyrene	193-39-5	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Manganese	7439-96-5	9.88E-08	9.88E-08	1.52E-04	1.45E-05	6.52E-05	1.30E-05	-	-	-	-	2.10E-06	-	b
Mercury	7439-97-6	6.76E-08	6.76E-08	1.04E-04	9.89E-06	4.46E-05	8.92E-06	-	-	-	-	1.44E-06	-	b
Methanol	67-56-1	-	-	-	1.56E+00	-	-	3.58E-02	3.03E-02	-	-	-	8.40E-02	b
Naphthalene	91-20-3	1.59E-07	1.59E-07	2.44E-04	2.32E-05	1.05E-04	2.09E-05	-	-	2.05E-04	-	3.37E-06	-	b
Nickel	7440-02-0	5.46E-07	5.46E-07	8.40E-04	7.99E-05	3.60E-04	7.21E-05	-	-	-	-	1.16E-05	-	b
Phenanathrene	85-01-8	4.42E-09	4.42E-09	6.80E-06	6.47E-07	2.92E-06	5.83E-07	-	-	-	-	9.39E-08	-	b, c
Pyrene	129-00-0	1.30E-09	1.30E-09	2.00E-06	1.90E-07	8.58E-07	1.72E-07	-	-	-	-	2.76E-08	-	b, c
Selenium	7782-49-2	6.24E-09	6.24E-09	9.60E-06	9.13E-07	4.12E-06	8.24E-07	-	-	-	-	1.33E-07	-	b
Toluene	108-88-3	8.84E-07	8.84E-07	1.36E-03	1.29E-04	5.83E-04	1.17E-04	-	-	3.21E-03	1.40E-04	1.88E-05	-	b
Xylene	1330-20-7	-	-	-	-	-	-	-	-	6.85E-03	4.26E-05	-	-	b
Total		6.72E-02	4.91E-04	7.55E-01	1.71E+00	3.24E-01	6.48E-02	3.58E-02	3.03E-02	1.67E-02	8.05E-04	1.04E-02	8.69E-02	-

Notes:

a. Criteria pollutant by name or association, i.e., VOC as surrogates for O3
b. Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.
c. HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of Clean Air Act
d. non-VOC per 40 CFR 51.100(s)(1); methane and ethane are not considered as regulated photochemical reactive VOC
e. Soot in concentration values, 0 micrograms per liter (ug/L); lightly smoking flares, 40 ug/L; average smoking flares, 177 ug/L; and heavily smoking flares 274 ug/L.
f. To be used where source testing or fuel analysis are not required by the AB2588 Criteria and Guidelines Regulations, Appendix D
g. Based on 100% conversion of fuel sulfur to SO2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

h. lb/hr Values in columns 024, 025, 029, and 030 are sourced from the Tanks Emissions Calculations
i. lb/hr Vlaues in column FUG are sourced from the Fugitive Emissions Calculations
j. the lb/hr vlaues for Methanol and Carbonyl Sulfide in Unit 007 are sourced from the Combustion Emissions Calculations
k. Thelb/hr value fro Carbonyl Sulfide in Unit 001 is sourced from the Flares Emissions Calculations

FUGITIVES

NAME Fugitive Emissions - Gasification, Shift Conversion, Methanation, AGR (Rectisol)

Unit ID: FUG

Methanol fugitives in the AGR (Rectisol) Unit: 100% Methanol

Fugitive Source	Stream Type	Component Count	Emission Factors lb/hr/component	Uncontrolled Emissions lb/hr	Control Efficiency %	Controlled Emissions lb/hr	Controlled Emissions TPY
Valves	Gas	0	0.0089	0	0	0	0
	Light Liquid	250	0.0035	0.875	0	0.88	3.83
	Heavy Liquid	0	0.0007	0	0	0	0
Flanges	Gas	0	0.0029	0	0	0	0
	Light Liquid	500	0.0005	0.250	0	0.25	1.10
	Heavy Liquid	0	0.00007	0	0	0	0
Pumps	Light Liquid	8	0.0386	0.309	0	0.31	1.35
	Heavy Liquid	0	0.0161	0	0	0	0
Compressors	Gas	0	0.5027	0	0	0	0
Relief Valves	Gas	0	0.2293	0	0	0	0
	Light Liquid	19	0.0035	0.067	0	0	0
Sampling Connections	All	4	0.033	0.132	0	0.132	0.578
Total Methanol		781				1.63	7.15

VOC fugitives in the AGR (Rectisol) Unit: 100% non-TAP VOC (propylene)

Fugitive Source	Stream Type	Component Count	Emission Factors lb/hr/component	Uncontrolled Emissions lb/hr	Control Efficiency %	Controlled Emissions lb/hr	Controlled Emissions TPY
Valves	Gas	78	0.0089	0.694	0	0.69	3.0
	Light Liquid	33	0.0035	0.116	0	0.12	0.51
	Heavy Liquid	0	0.0007	0	0	0	0
Flanges	Gas	193	0.0029	0.560	0	0.56	2.45
	Light Liquid	82	0.0005	0.041	0	0.041	0.18
	Heavy Liquid	0	0.00007	0	0	0	0
Pumps	Light Liquid	2	0.0386	0.077	0	0.077	0.34
	Heavy Liquid	0	0.0161	0	0	0	0
Compressors	Gas	3	0.5027	1.508	0	1.51	6.61
Relief Valves	Gas	7	0.2293	1.605	0	2	7
	Light Liquid	0	0.0035	0	0	0	0
Sampling Connections	All	1	0.033	0.033	0	0.033	0.145
Total VOCs		399				4.63	20.30

Carbonyl Sulfide

Fugitive Source	Process Stream	Component Count	COS Conc %v	Emission Factors lb/hr/component	Uncontrolled Emissions lb/hr	Control Efficiency %	Controlled Emissions lb/hr	Controlled Emissions TPY
Valves	Raw Syngas	100	0.029	0.0089	0.00026	0	2.6E-04	1.1E-03
	Shifted Syngas	50	0.008	0.0089	0.00003	0	3.3E-05	1.5E-04
	Mixed Syngas	100	0.024	0.0089	0.00022	0	2.2E-04	0.00095
	Sweet Syngas	20	5.0E-07	0.0089	8.9E-10	0	8.9E-10	3.9E-09
Flanges	Raw Syngas	250	0.029	0.0029	0.00021	0	2.1E-04	0.00093
	Shifted Syngas	100	0.008	0.0029	0.00002	0	2.2E-05	9.5E-05
	Mixed Syngas	250	0.024	0.0029	0.00018	0	1.8E-04	0.00077
	Sweet Syngas	50	5.0E-07	0.0029	7.3E-10	0	7.3E-10	3.2E-09
Compressor Seals	Raw Syngas	0	0.029	0.5027	0	0	0	0
	Shifted Syngas	0	0.008	0.5027	0	0	0	0
	Mixed Syngas	0	0.024	0.5027	0	0	0	0
	Sweet Syngas	0	5.0E-07	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.029	0.0386	0	0	0	0
	Shifted Syngas	0	0.008	0.0386	0	0	0	0
	Mixed Syngas	0	0.024	0.0386	0	0	0	0
	Sweet Syngas	0	5.0E-07	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.029	0.2293	0.00134	0	0.0013	0.0059
	Shifted Syngas	4	0.008	0.2293	0.00007	0	6.9E-05	3.0E-04
	Mixed Syngas	8	0.024	0.2293	0.00045	0	4.5E-04	0.00196
	Sweet Syngas	4	5.0E-07	0.2293	4.6E-09	0	4.6E-09	2.01E-08
Sample Connections	Raw Syngas	2	0.029	0.033	0.00002	0	1.9E-05	8.5E-05
	Shifted Syngas	2	0.008	0.033	0.00000	0	5.0E-06	2.2E-05
	Mixed Syngas	2	0.024	0.033	0.00002	0	1.6E-05	7.0E-05
	Sweet Syngas	2	5.0E-07	0.033	3.3E-10	0	3.3E-10	1.4E-09
Total COS							2.8E-03	1.2E-02

No Control Efficiency claimed due to low concentration.

Total VOCs = 6.27 27.46

Carbon Monoxide

Fugitive Source	Process Stream	Component Count	CO Conc %v	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
				lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	20.4	0.0089	0.18156	0	0.1816	0.795
	Shifted Syngas	50	3.7	0.0089	0.01666	0	1.7E-02	0.073
	Mixed Syngas	100	14.8	0.0089	0.13181	0	0.1318	0.577
	Sweet Syngas	20	22.5	0.0089	0.03997	0	0.0400	0.175
Flanges	Raw Syngas	250	20.4	0.0029	0.14790	0	0.1479	0.648
	Shifted Syngas	100	3.7	0.0029	0.01086	0	0.0109	0.048
	Mixed Syngas	250	14.8	0.0029	0.10737	0	0.1074	0.470
	Sweet Syngas	50	22.5	0.0029	0.03256	0	0.0326	0.143
Compressor Seals	Raw Syngas	0	20.4	0.5027	0	0	0	0
	Shifted Syngas	0	3.7	0.5027	0	0	0	0
	Mixed Syngas	0	14.8	0.5027	0	0	0	0
	Sweet Syngas	0	22.5	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	20.4	0.0386	0	0	0	0
	Shifted Syngas	0	3.7	0.0386	0	0	0	0
	Mixed Syngas	0	14.8	0.0386	0	0	0	0
	Sweet Syngas	0	22.5	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	20.4	0.2293	0.93554	0	0.9355	4.0977
	Shifted Syngas	4	3.7	0.2293	0.03434	0	0.0343	0.1504
	Mixed Syngas	8	14.8	0.2293	0.27167	0	0.2717	1.1899
	Sweet Syngas	4	22.5	0.2293	0.20596	0	0.2060	0.9021
Sample Connections	Raw Syngas	2	20.4	0.033	0.01346	0	1.3E-02	0.0590
	Shifted Syngas	2	3.7	0.033	0.00247	0	2.5E-03	1.1E-02
	Mixed Syngas	2	14.8	0.033	0.00977	0	9.8E-03	0.0428
	Sweet Syngas	2	22.5	0.033	0.01482	0	1.5E-02	0.0649
Total CO							2.157	9.446

Hydrogen Sulfide

Fugitive Source	Process Stream	Component Count	H2S Conc %v	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
				lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	0.58	0.0089	0.00519	0	5.2E-03	0.023
	Shifted Syngas	50	0.61	0.0089	0.00269	0	2.7E-03	0.012
	Mixed Syngas	100	1.10	0.0089	0.00978	0	9.8E-03	0.043
	Sweet Syngas	20	2.8E-06	0.0089	5.0E-09	0	5.0E-09	2.2E-08
Flanges	Raw Syngas	250	0.58	0.0029	0.00423	0	4.2E-03	0.019
	Shifted Syngas	100	0.61	0.0029	0.00176	0	1.8E-03	7.7E-03
	Mixed Syngas	250	1.10	0.0029	0.00797	0	8.0E-03	0.035
	Sweet Syngas	50	2.8E-06	0.0029	4.1E-09	0	4.1E-09	1.8E-08
Compressor Seals	Raw Syngas	0	0.58	0.5027	0	0	0	0
	Shifted Syngas	0	0.61	0.5027	0	0	0	0
	Mixed Syngas	0	1.10	0.5027	0	0	0	0
	Sweet Syngas	0	2.8E-06	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.58	0.0386	0	0	0	0
	Shifted Syngas	0	0.61	0.0386	0	0	0	0
	Mixed Syngas	0	1.10	0.0386	0	0	0	0
	Sweet Syngas	0	2.8E-06	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.58	0.2293	0.02675	0	0	0
	Shifted Syngas	4	0.61	0.2293	0.00555	0	0	0
	Mixed Syngas	8	1.10	0.2293	0.02016	0	0	0
	Sweet Syngas	4	2.8E-06	0.2293	2.6E-08	0	0	0
Sample Connections	Raw Syngas	2	0.58	0.033	0.00039	0	3.9E-04	1.7E-03
	Shifted Syngas	2	0.61	0.033	0.00040	0	4.0E-04	1.7E-03
	Mixed Syngas	2	1.10	0.033	0.00073	0	7.3E-04	3.2E-03
	Sweet Syngas	2	2.8E-06	0.033	1.9E-09	0	1.9E-09	8.2E-09
Total Hydrogen Sulfide							0.086	0.375

No Control Efficiency claimed for components in sweet syngas service due to low concentration.

Ammonia

Fugitive Source	Process Stream	Component Count	NH3 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
			%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	0.0012	0.0089	1.0E-05	0	1.0E-05	4.5E-05
	Shifted Syngas	50	0.0012	0.0089	5.2E-06	0	5.2E-06	2.3E-05
	Mixed Syngas	100	0.0012	0.0089	1.0E-05	0	1.0E-05	4.5E-05
	Sweet Syngas	20	0	0.0089	0	0	0	0
Flanges	Raw Syngas	250	0.0012	0.0029	8.4E-06	0	8.4E-06	3.7E-05
	Shifted Syngas	100	0.0012	0.0029	3.4E-06	0	3.4E-06	1.5E-05
	Mixed Syngas	250	0.0012	0.0029	8.4E-06	0	8.4E-06	3.7E-05
	Sweet Syngas	50	0	0.0029	0	0	0	0
Compressor Seals	Raw Syngas	0	0.0012	0.5027	0	0	0	0
	Shifted Syngas	0	0.0012	0.5027	0	0	0	0
	Mixed Syngas	0	0.0012	0.5027	0	0	0	0
	Sweet Syngas	0	0	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.0012	0.0386	0	0	0	0
	Shifted Syngas	0	0.0012	0.0386	0	0	0	0
	Mixed Syngas	0	0.0012	0.0386	0	0	0	0
	Sweet Syngas	0	0	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.0012	0.2293	5.3E-05	0	5.3E-05	2.3E-04
	Shifted Syngas	4	0.0012	0.2293	1.1E-05	0	1.1E-05	4.7E-05
	Mixed Syngas	8	0.0012	0.2293	2.1E-05	0	2.1E-05	9.3E-05
	Sweet Syngas	4	0	0.2293	0	0	0	0
Sample Connections	Raw Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Shifted Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Mixed Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Sweet Syngas	2	0	0.033	0	0	0	0
Total Ammonia							1.3E-04	5.8E-04

Notes:

1 Component counts are preliminary subject to change during detailed project engineering.
2 Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3 Relief valves discharge to flare.
4 No LDAR program is required for syngas streams, therefore, no control efficiency assumed.

NAME Fugitive Emissions - Wet Sulfuric Acid Units

Unit ID: FUG - WSA

Summary of Fugitive Vapor Emissions for Wet Sulfuric Acid Process

H2S

Fugitive Source	Process Stream	Component Count		H2S Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	10	20	44.00	0.00890	0.0783	0	0.0783	0.3430
Flanges	Acid Gas	100	200	44.00	0.00290	0.2552	0	0.2552	1.1178
Compressor Seals	Acid Gas	0	0	44.00	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	44.00	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	2	4	44.00	0.22930	0.4036	0	0.4036	1.7676
Sample Connections	Acid Gas	4	8	44.00	0.03300	0.1162	0	0.11616	0.5088
Total H2S								0.8532	3.7372

SO2

Fugitive Source	Process Stream	Component Count		SO2 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	6.20	0.00890	0	0	0.0000	0.0000
Flanges	Acid Gas	20	40	6.20	0.00290	0.0072	0	0.0072	0.0315
Compressor Seals	Acid Gas	0	0	6.20	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	6.20	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	0	0	6.20	0.22930	0	0	0.0000	0.0000
Sample Connections	Acid Gas	4	8	6.20	0.03300	0.0164	0	0.01637	0.0717
Total SO2								0.0236	0.1032

SO3

Fugitive Source	Process Stream	Component Count		SO3 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	3.30	0.00890	0.0000	0	0.0000	0.0000
Flanges	Acid Gas	30	60	3.30	0.00290	0.0057	0	0.0057	0.0251
Compressor Seals	Acid Gas	0	0	3.30	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	3.30	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	0	0	3.30	0.22930	0.0000	0	0.0000	0.0000
Sample Connections	Acid Gas	3	6	3.30	0.03300	0.0065	0	0.00653	0.0286
Total SO3								0.0123	0.0538
Total SO3 as H2SO4								0.01504	0.0659

H2SO4 Vapor

Fugitive Source	Process Stream	Component Count		Acid Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	3.60	0.00890	0.0000	0	0.0000	0.0000
Flanges	Acid Gas	10	20	3.60	0.00290	0.0021	0	0.0021	0.0091
Compressor Seals	Acid Gas	0	0	3.60	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	3.60	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	0	0	3.60	0.22930	0.0000	0	0.0000	0.0000
Sample Connections	Acid Gas	1	2	3.60	0.03300	0.0024	0	0.00238	0.0104
Total H2SO4								0.0045	0.0196
Total H2SO4 including SO3								0.020	0.0854

Notes:

1 Component counts are preliminary subject to change during detailed project engineering.
2 Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3 Relief valves discharge to flare.

NAME Fugitive Emissions - Greenhouse Gas Emissions Only (from Gasification/SNG and from WSA)

Unit ID: FUG & FUG-WSA

CO2 in WSA (FUG-WSA)

Emission Source	Source Process Stream	Total Component Count	Conc %w	Average Emissions Factor lb/hr	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Acid Gas	20	**42.90**	**0.00890**	0.076		0.0764	0.3345
Flanges	Acid Gas	200	**42.90**	**0.00290**	0.249		0.2488	1.0898
Compressor Seals	Acid Gas	0	**42.90**	**0.50270**	0.000		0.0000	0.0000
Pump Seals	Acid Gas	0	**42.90**	**0.03860**	0.000		0.0000	0.0000
Relief Valves	Acid Gas	4	**42.90**	**0.22930**	0.393		0.3935	1.7234
Sample Connections	Acid Gas	8	**42.90**	**0.03300**	0.113		0.1133	0.4961
Total					**0.832**		**0.8319**	**3.644**

Carbon Dioxide from FUG

Emission Source	Source Process Stream	Component Count	CO2 Conc %v	Emissions Factor lb/hr/component (discounted by %v)	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Raw Syngas	100	6.2	0.001	0.055		0.0554	0.243
	Shifted Syngas	50	23.6	0.002	0.105		0.1049	0.460
	Mixed Syngas	100	32.2	0.003	0.287		0.2867	1.256
	Sweet Syngas	20	6.3	0.001	0.011		0.0112	0.049
	CO2	30	99.0	0.009	0.264		0.2643	1.158
Flanges	Raw Syngas	250	6.2	0.000	0.045		0.0451	0.198
	Shifted Syngas	100	23.6	0.001	0.068		0.0684	0.299
	Mixed Syngas	250	32.2	0.001	0.234		0.2335	1.023
	Sweet Syngas	50	6.3	0.000	0.009		0.0092	0.040
	CO2	60	99.0	0.003	0.172		0.1723	0.754
Compressor Seals	Raw Syngas	0	6.2	0.031	0.000	0	0.0000	0.000
	Shifted Syngas	0	23.6	0.119	0.000	0	0.0000	0.000
	Mixed Syngas	0	32.2	0.162	0.000	0	0.0000	0.000
	Sweet Syngas	0	6.3	0.032	0.000	0	0.0000	0.000
	CO2	16	99.0	0.498	7.963	0	7.9628	34.877
Pump Seals	Raw Syngas	0	6.2	0.002	0.000		0.0000	0.000
	Shifted Syngas	0	23.6	0.009	0.000		0.0000	0.000
	Mixed Syngas	0	32.2	0.012	0.000		0.0000	0.000
	Sweet Syngas	0	6.3	0.002	0.000		0.0000	0.000
	CO2	0	99.0	0.038	0.000		0.0000	0.000
Relief Valves	Raw Syngas	20	6.2	0.014	0.286		0.2856	1.251
	Shifted Syngas	4	23.6	0.054	0.216		0.2162	0.947
	Mixed Syngas	8	32.2	0.074	0.591		0.5909	2.588
	Sweet Syngas	4	6.3	0.014	0.058		0.0580	0.254
	CO2	3	99.0	0.227	0.681		0.6810	2.983
Sample Connections	Raw Syngas	2	6.2	0.002	0.004		0.0041	0.018
	Shifted Syngas	2	23.6	0.008	0.016		0.0156	0.068
	Mixed Syngas	2	32.2	0.011	0.021		0.0213	0.093
	Sweet Syngas	2	6.3	0.002	0.004		0.0042	0.018
	CO2	2	99.0	0.033	0.065		0.0653	0.286
Total					**11.091**		**11.1559**	**48.863**
					48.577			

Methane from FUG

Emission Source	Source Process Stream	Component Count	CH4 Conc %v	Emissions Factor lb/hr/component	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Raw Syngas	100	0.025	0.000	0.000	0	0.0002	0.001
	Shifted Syngas	50	0.025	0.000	0.000	0	0.0001	0.000
	Mixed Syngas	100	0.060	0.000	0.001	0	0.0005	0.002
	Sweet Syngas	20	0.063	0.000	0.000	0	0.0001	0.000
	Fuel Gas	25	94.2	0.008	0.210	0	0.2096	0.918
	SNG	10	94.2	0.008	0.084	0	0.0838	0.367
Flanges	Raw Syngas	250	0.025	0.000	0.000	0	0.0002	0.001
	Shifted Syngas	100	0.025	0.000	0.000	0	0.0001	0.000
	Mixed Syngas	250	0.060	0.000	0.000	0	0.0004	0.002
	Sweet Syngas	50	0.063	0.000	0.000	0	0.0001	0.000
	Fuel Gas	30	94.2	0.003	0.082	0	0.0820	0.359
	SNG	20	94.2	0.003	0.055	0	0.0546	0.239
Compressor Seals	Raw Syngas	0	0.025	0.000	0.000	0	0.0000	0.000
	Shifted Syngas	0	0.025	0.000	0.000	0	0.0000	0.000
	Mixed Syngas	0	0.060	0.000	0.000	0	0.0000	0.000
	Sweet Syngas	0	0.063	0.000	0.000	0	0.0000	0.000
	Fuel Gas	0	95	0.008	0.000	0	0.0000	0.000
	Fuel Gas	0	94.2	0.474	0.000	0	0.0000	0.000
	SNG	4	94.2	0.474	1.894	0	1.8942	8.296
Pump Seals	Raw Syngas	0	0.025	0.000	0.000	0	0.0000	0.000
	Shifted Syngas	0	0.025	0.000	0.000	0	0.0000	0.000
	Mixed Syngas	0	0.060	0.000	0.000	0	0.0000	0.000
	Sweet Syngas	0	0.063	0.000	0.000	0	0.0000	0.000
	Fuel Gas	0	94.2	0.036	0.000	0	0.0000	0.000
	SNG	0	94.2	0.036	0.000	0	0.0000	0.000
Relief Valves	Raw Syngas	20	0.025	0.000	0.001	0	0.0011	0.005
	Shifted Syngas	4	0.025	0.000	0.000	0	0.0002	0.001
	Mixed Syngas	8	0.060	0.000	0.001	0	0.0011	0.005
	Sweet Syngas	4	0.063	0.000	0.001	0	0.0006	0.003
	Fuel Gas	1	94.2	0.216	0.216	0	0.2160	0.946
	SNG	2	94.2	0.216	0.432	0	0.4320	1.892
Sample Connections	Raw Syngas	2	0.025	0.000	0.000	0	0.0000	0.000
	Shifted Syngas	2	0.025	0.000	0.000	0	0.0000	0.000
	Mixed Syngas	2	0.060	0.000	0.000	0	0.0000	0.000
	Sweet Syngas	2	0.063	0.000	0.000	0	0.0000	0.000
	Fuel Gas	0	94.2	0.031	0.000	0	0.0000	0.000
	SNG	1	94.2	0.031	0.031	0	0.0311	0.136
Total					**2.977**		**3.0082**	**13.176**

TPY CO$_2$e from FUG= 325.56

Notes:
1 Component counts are preliminary subject to change during detailed project engineering.
2 Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3 Relief valves discharge to flare

CALCULATION SHEET

Emission Unit	**Emission Description**
FUG-ROAD-C (Coal Trucks)	Fugitive Dust: Paved Road Truck Traffic for Coal/Coke delivery by Truck

Calculation Methodology

AP-42 Chapter 13, Section 2.1 : Miscellaneous Sources, Paved Roads

Max Hourly and Daily Emissions calculated using equation (1)

$$\boxed{E = k(sL)^{0.91} \times (W)^{1.02}}$$

Annual Emissions calculated using equation (2)

$$\boxed{E_{ext} = \left[k(sL)^{0.91} \times (W)^{1.02}\right](1 - P/4N)}$$

k factor from Table 13.2.1-1

PM = 0.011

PM10 = 0.0022

PM2.5 = 0.00054

Road Surface Silt Loading, sL = 1.0 g/m^2 (Conservative value considering planned frequent watering)

EmptyTruck weight = 9.7 tons

Full Truck weight = 41.7 tons

"Wet" days, P = 117 days

Number of days in averaging period, N = 365

Calculation of Potential Emissions:

Average Round-Trip Distance:	0.479	mile/trip	"Wet" Days, P:	117	days	
Road Surface Silt Loading, sL:	1.0	g/m^2	Days in Ave. Period, N:	365	days	
Average Truck Weight, W:	25.7	tons	Highest Day Wet Coal	249.1	tons/hr	50% plant capacity
Particle Size Multiplier, k:	0.0022	PM10	Carried each Load:	32.0	tons/truck	
Particle Size Multiplier, k:	0.00054	PM2.5	Truck Trips:	186.8	trip/day	
Particle Size Multiplier, k:	0.011	PM	Truck Trips:	100.9	daily trip (yr avg)	54% of daily trips
			Control Efficiency for Watering:	90%		

Potential PM10 Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.0225	0.54	0.0906

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.0055	0.13	0.0222

Potential PM Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.1124	2.70	0.4531

CALCULATION SHEET

Emission Unit	**Emission Description**
FUG-ROAD-S (Slag)	Fugitive Dust: Paved Roads for Slag Truck Hauling

Calculation Methodology

AP-42 Chapter 13, Section 2.1 : Miscellaneous Sources, Paved Roads
Max Hourly and Daily Emissions calculated using equation (1) emissions factor

$$\boxed{E = k(sL)^{0.91} \times (W)^{1.02}}$$

Annual Emissions calculated using equation (2) emissions factor

$$\boxed{E_{ext} = \left[k(sL)^{0.91} \times (W)^{1.02}\right](1 - P/4N)}$$

k factor from Table 13.2.1-1
PM = 0.011
PM10 = 0.0022
PM2.5 = 0.00054
EmptyTruck weight = 9.7 tons
Load each trip = 20 tons
"Wet" days, P = 117 days
Number of days in averaging period, N = 365

Trip Distance = 600 ft, each way in process block (normal). Additionally, if slag hauled to coal yard temporary storage, then it must travel 900 feet offsite to coal yard area, then it travels 1100 feet in coal yard to drop off and 1100 feet in coal yard to pick up. (worse-case total = 600+600+1100+1100 excluding the portion of travel "offsite"/outside the fenceline.)

Emissions calculated = Emissions factor (lb/vmt) * trip distance (miles) * number of trips * (1-control efficiency)

Calculation of Potential Emissions:

Total Round-Trip Distance:	0.644	mile/trip	"Wet" Days, P:	117	days
Road Surface Silt Loading, sL:	1.0	g/m^2	Days in Ave. Period, N:	365	days
Average Truck Weight, W:	19.7	tons	Slag Production:	43.08	tons/hr
Particle Size Multiplier, k:	0.0022	PM10	Carried each Load:	20.0	tons/truck
Particle Size Multiplier, k:	0.00054	PM2.5	Truck Trips:	82.7	trip/day (includes 31 trucks/day contingency)
Particle Size Multiplier, k:	0.011	Total PM	Control Efficiency for Watering:	90%	

Potential PM10 Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0102	0.24	0.0411

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0025	0.06	0.0101

Potential Total PM Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0510	1.22	0.2056

Process Road Segment

PM10	0.0036	lb/hr
PM2.5	0.00088	lb/hr
Total PM	0.01801	lb/hr

Coal Yard Road Segment

PM10	0.0066	lb/hr
PM2.5	0.0016	lb/hr
Total PM	0.0330	lb/hr

CALCULATION SHEET

Emission Unit	**Emission Description**
EU-034A	Handling (Drop) emissions for handling/loading Slag at temp. Storage pile.

Calculation Methodology

AP-42 Chapter 13, Section 2.4:Aggregate Handling and Storage Piles
Uncontrolled Emissions per handling step calculated using equation (1)

$$E = k\,(0.0032)\,\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

$$E = k\left(0.0032\right)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where:
E = emissions factor in lbs emissions per ton aggregate handled
U = mean wind speed, mph
M = material moisture content
k = particle size multplier (dimensionless)
Total PM k = 0.74
PM10 k = 0.35
PM2.5 k = 0.053

Assume that slag dumped from trucks coming from process is so wet that there are no emissions.

Also assume when/if slag is initially picked up by front end loader and piled or moved within storage site that it is still wet enough to not have emissions
Then assume slag is picked up by front end loader and loaded into truck for haulting out (1 handling step)
Assume watering used to keep slag wet. Control effectiveness of watering reflected in assumed moisture content.

Calculation of Potential Emissions:

Number of Drops(handling steps)	1.000	drops	Maximum daily slag	1,034	tons/day max
Mean wind speed	8.0	mph	Max hourly slag	43.08	tons/hr
Material Moisture content	15.00	%	Annual Slag Production:	720.0	tons/day annual average
Particle Size Multiplier, k:	0.35	PM10	Average hourly slag	30	tons/hr annual average
Particle Size Multiplier, k:	0.053	PM2.5	Hours per yr of activity	8760.0	
Particle Size Multiplier, k:	0.74	Total PM	Control Efficiency for Watering	Addressed by moisture content assumption	

Potential PM10 Emissions:

EP	Max lb/hr	Max lb/day	tpy
EU-034A	0.0053	0.13	0.0161

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
EU-034A	0.0008	0.02	0.0024

Potential Total PM Emisions:

EP	Max lb/hr	lb/day	tpy
EU-034A	0.0112	0.27	0.0341

EU-034C Emission Calculation for Front-End Loader and Slag truck Activity on the temp. Slag storage pad/pile

Although Storage Pad is paved, assume it is partially covered in slag, calculate emissions assuming unpaved road equation.

Description of Vehicles	Load Size tons	Vehicle Weight Empty tons	Average Vehicle Weight tons	Daily Slag (annual average) tons/day	Max Slag per day tons/day	Miles per trip Mile/trip	Maximum Daily Trips/day	Ave Annual Trips/day	Maximum VMT Miles/day	Ave. Annual VMT Miles/day
Front End Loader	20	32.66	26.33	1,440	2,068	0.0142	103.4	72	1.469	1.023

Note: Slag handled is slag production assuming that slag is either delivered to or picked up from the storage pad each day. (Not being dropped off all day and being picked up all day on the same day).
Assume each trip of front end loader trip is 75 feet round trip (1/4 width of pad times 2)

	Average Vehicle weigh (tons)	Uncontrolled Emissions factor (lbs total PM/VMT)	Uncontrolled Emissions factor (lbs PM10/VMT)	Uncontrolled Emissions factor (lbs PM2.5/VMT)	Control Efficiency	Max daily lb/hr Total PM	Max daily lb/hr PM10	Max daily lb/hr PM2.5	
Front End Loader/dozer	26.33	2.287	0.426	0.043	90%	0.014	0.003	0.000	**Front End Loader**
					Total	**0.014**	**0.003**	**0.000**	

	Max Annual Tons/yr Total PM	Max Annual Tons/yr PM10	Max Annual Tons/yr PM2.5	
	0.007	0.001	0.000	**Front End Loader**
Total	**0.007**	**0.001**	**0.000**	

UNPAVED ROADS EQUATIONS Industrial Roads - AP42 13.2.4 (equations 1a and 2)

$$E = k * \left(s/12\right)^{a} * \left(W/3\right)^{b}$$

$$E_{ext} = E\left(\frac{365-P}{365}\right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range (lb/VMT)
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Vehicle average weight (tons)
P = number of days per year with 0.01 in or more of precipitation

INPUTS TO EQUATION/CALCULATIONS	Total PM	PM10	PM2.5	
k	4.9	1.5	0.15	lb/vmt
s	1	1	1	%
a	0.7	0.9	0.9	
b	0.45	0.45	0.45	
P	117	117	117	days/yr

Indiana Gasification, LLC Spencer County Facility

Emission Unit:

FUG-SF6 Emission Estimate for Fugitive Emissions of SF_6 from Circuit Breakers

The IG facility will include a switchyard with circuit breakers that include sulfur hexafluoride (SF_6), a greenhouse gas, as a gaseous dielectric.
The circuit breakers will be totally enclosed and pressurized.
Fugitive emissions are estimated as 1% leakage per year.

Emission Calculation

Number of circuit breal	6	
Amount of SF_6 in each	100	lbs
Assumed leak rate:	1%	
Emissions (lb/yr):	6	lbs/yr
GWP of SF_6:	23,900	
CO2e (tons/yr):	71.7	tons/yr

8,339,799.29

Basis:	**100%w Coal with Gasifier Methanol Startups**
4	Operating GE Quench Gasifiers (design capacity x 1.25)
10,401	STPD dry coal (design capacity x 1.25)
12,968	BTU/lb dry HHV/lb coal design
11,240	MMBTU/hr HHV coal (design capacity x 1.25)
3.66	%wt dry sulfur in coal during normal operation
600	MMSCFD H2+CO2 Total Raw Syngas from Gasifiers (design capacity x 1.25)
154	MMSCFD SNG Gross Production (design capacity x 1.25)
302.2	MMSCFD CO2 Captured
0	MMSCFD CO2 to EOR Pipeline
1,164	STPD 100%w H2SO4

		Installed	Operating	Preliminary	Operating Rate		Estimated	Mercury			Lead		
EPN #	**Emission Units**	**Number of Stacks**	**Number of Stacks**	**Stack Height feet**	**Rating**	**Units**	**Annual Operating Hours**	**lb/MMBTU**	**lb/hr**	**Tons/yr**	**lb/MMBTU**	**lb/hr**	**Tons/yr**
001	Gasifier Startup Flare Emissions **(methanol fuel)** - 90 per year at 90 min	1	1	300	862	MMBtu/h HHV	8760						
001	Syngas Flare - Nat Gas Pilots	1	1	300	0.27	MMBtu/h HHV	8760	1.65E-06	4.376E-07	0.0000019	2.90E-06	7.69E-07	0.0000034
002	Acid Gas Flare - Nat Gas Pilots	1	1	300	0.27	MMBtu/h HHV	8760	1.65E-06	4.376E-07	0.0000019	2.90E-06	7.69E-07	0.0000034
005	Auxiliary Boiler, Full Load Operation - black plant su (nat gas fuel)	1	1	200	816	MMBtu/h HHV	8760	2.55E-07	2.081E-04	0.0009072	4.90E-07	4.00E-04	0.0017447
005	Auxiliary Boiler, Full Load Operation (SNG or Nat Gas)	1	1	200	816	MMBtu/h HHV	8760	1.65E-06	1.347E-03	0.0058725	2.90E-06	2.37E-03	0.0103217
005	Auxiliary Boiler, Half Load Operation (SNG or Nat Gas)	1	1	200	408	MMBtu/h HHV	0	1.65E-06	6.735E-04	0.0029363	2.90E-06	1.18E-03	0.0051608
008	Gasifier Preheat Burners - black plant su (nat gas fuel)	5	5	200	35	MMBtu/h HHV	8760	2.55E-07	8.922E-06	0.0000389	4.90E-07	1.72E-05	0.0000748
008	Gasifier Preheat Burners (one operating 8 months per year, SNG or NG fuel	5	1	200	18	MMBtu/h HHV	8760	1.65E-06	2.970E-05	0.0001295	2.90E-06	5.22E-05	0.0002276
009	Emergency Diesel Generators (2 units each tested 1 hour weekly)	2	1	20	1,341	hp	500						
010	Diesel Fire Water Pump Engine (3 units each tested 1 hour weekly)	3	1	20	575	hp	500						
011	Coal Conveying and Feed Bins Dust Control System Vents	2	1	200	Rated in terms of Plant Capacity		8760		1.244E-06	0.0000054		2.42E-04	0.0010546
012	Coal Unloading and Storage (Barge, Rail, Truck)									0.0000000			0.0000000
013	Rod Mill Vent Stacks	4	4	125	Rated in terms of Plant Capacity		8760			0.0000000			0.0000000
032	ZLD Spray Drier Stack	1	1	100	5.6	MMBtu/h HHV	8760	1.65E-06	9.294E-06	0.0000405	2.90E-06	1.63E-05	0.0000712
033	ZLD Inert Gas Vent	1	1	100	Rated in terms of Plant Capacity		8760		1.404E-07	0.0000006			
015	WSA Preheat	2	1	200	35.0	MMBtu/h HHV	8760	1.65E-06	5.775E-05	0.0002518	2.90E-06	1.02E-04	0.0004425
015	WSA Stack - black plant su	2	1	213	291	stpd 100% H2SO4	8760		8.348E-11	0.0000000			
015	WSA Stack - One Unit Operation	2	1	213	582	stpd 100% H2SO4	8760		1.670E-10	0.0000000			
015	WSA Stack - Two Unit Operation	2	2	213	1,164	stpd 100% H2SO4	8760		3.339E-10	0.0000000			
16a	Cooling Tower -ASU	6	6	65	Rated in terms of Plant Capacity		8760						
16b	Cooling Tower -Main	24	24	65	Rated in terms of Plant Capacity		8760						
017	ASU Molecular Sieve Regeneration Vents	2	Int	60	Rated in terms of Plant Capacity		8760						
024	Methanol Storage Scrubber Vent Stack	1	Int	30	Rated in terms of Plant Capacity		8760						
	Fugitive Emissions - Gasification, Shift Conversion, Rectisol, Methanation	NA	NA				8760						
	Fugitive Emissions - WSA	NA	NA				8760						
	Plant Totals without CO2 Venting								**0.002336**	**0.01**		**0.004382**	**0.02**

RTO Case

007	Regen Thermal Oxidizers -black plant su, one gasifier op (nat gas fuel)	1	1	200	19.4	MMBtu/h HHV NG	8760	1.65E-06	3.202E-05	0.0001396	2.90E-06	5.63E-05	0.0002454
007	Regen Thermal Oxidizers (Note 1, Two Units Hot Standby 80% of the year, SNG	1	1	200	10.3	MMBtu/h HHV SNG	0	1.65E-06	1.705E-05	0.0000743	2.90E-06	3.00E-05	0.0001307
007	Regen Thermal Oxidizers (Note 1, One Unit Op, SNG fuel)	1	1	200	38.8	MMBtu/h HHV SNG	8760	1.65E-06	6.404E-05	0.0002792	2.90E-06	1.13E-04	0.0004907
007	Regen Thermal Oxidizers (Note 1, Two Units with common, SNG fuel)	1	1	200	77.6	MMBtu/h HHV SNG	8760	1.65E-06	1.281E-04	0.0005584	2.90E-06	2.25E-04	0.0009815
007	**RTO Totals**								0.000241	0.00		**0.000199**	0.001848
	Plant Totals with 100% CO2 to RTO								**0.002578**	**0.01**		**0.004581**	**0.02**

Notes:

1 Mercury and lead emissions are based on firing SNG in pilots, aux boiler and WSA preheater except for black plant su. RTO Hg and Pb emissions are based on SNG including black plant su.

Plant Mercury Balance for 125% of design plant operating rate

Mercury in Natural Gas:

2.60E-04	lb mercury/MMSCF natural gas	from EPA AP-42 Natural Gas Combustion
1.02E+03	BTU/SCF natural gas HHV	from EPA AP-42 Natural Gas Combustion
2.55E-07	lb mercury/MMBTU HHV natural gas	calculated

Mercury in Solids Feed to Gasifiers:

0.11	ppm dry mercury is average reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 24A
0.86	ppm dry mercury is maximum reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 24A

	Total stph dry	**Mercury max ppm, dry**	**Mercury max lb/hr**
Coal:	433.38	0.86	0.745
Coke:	0.00	0.05	
Total coal + coke	433.38		0.745

Output streams:	max mercury	
Slag	0%	mercury in gasifier feed goes out in slag (maximum Hg to wastewater)
	0.0000	lb/hr Hg in slag
Wastewater	2%	mercury in gasifier feed goes out in gasification process wastewater
	0.0149	lb/hr Hg in gasification process wastewater
	0.5	ppbv Hg in ZLD vent gas from sulfided carbon mercury removal guaranteed
	1.4	lb-mole/hour ZLD vent gas
	7E-10	lb-moles/hour mercury in ZLD vent gas
	200.59	lb/lb-mole mercury molecular weight
	1.40E-07	lb/hr mercury in ZLD vent gas
	1.49E-02	lb/hr mercury removed by sulfided carbon
Syngas to Sulfided Carbon	98%	mercury in gasifier feed is in syngas to mercury removal
	0.7305	lb/hr Hg in syngas to mercury removal
Syngas from Sulfided Carbon	0.5	ppbv Hg in syngas from mercury removal guaranteed
	103,526	lb-moles/hr total syngas from mercury removal
	5.18E-05	lb-moles/hr Hg in syngas from mercury removal
	0.010	lb/hr mercury in syngas to Rectisol
	98.6%	mercury removal on sulfided carbon
Rectisol Treated Syngas	66,958	lb-moles/hr treated syngas from Rectisol
	-27	F Treated Rectisol syngas from absorber
	99.99998%	Hg in syngas to Rectisol assumed to be in syngas from Rectisol (worst case no accumulation in Rectisol)
	0.0104	lb/hr mercury in syngas from Rectisol
	0.77	ppbv Hg in Rectisol treated syngas
SNG	0.0104	lb/hr mercury in SNG
	2.94	ppbv Hg in SNG
	6,293	MMBTU/hr HHV SNG rate
	1.65E-06	lb Hg/MMBTU HHV SNG
Rectisol CO2	33,184	lb-moles/hr CO2 from Rectisol
	-42	F CO2 Temperature from MP Flash
	1.45E-08	lb Hg solubility/lb Methanol
	3.28E-06	Vapor pressure of Hg, mbar
	2.89E-07	ppbv Hg in CO2 from Rectisol
	1.92E-09	lb/hr Hg in CO2
Rectisol Acid Gas	3,264	lb-moles/hr acid gas from Rectisol
	-31	F acid gas temperature at the acid gas separator
	2.71E-08	lb Hg solubility/lb Methanol
	4.98E-06	Vapor pressure of Hg, mbar at -31F
	5.10E-07	ppbv Hg in acid gas from Rectisol
	3.34E-10	lb/hr Hg in acid gas
Coal Particulate Emissions	1.45	lb/hr coal dust from Coal Conveying and Feed Bins Dust Control System Vents
	1.24E-06	lb/hr mercury in coal dust from coal converying and feed bins dust control system vents
	1.09E-02	lb/yr mercury in coal dust from coal conveying and feed bins dust control system vents
	10.39	tons per year coal dust from coal unloading and storage
	1.79E-02	lb/yr mercury in coal dust from coal unloading and storage
	0.44	tons per year coal dust from rod mills
	7.57E-04	lb/yr mercury in coal dust from rod mills

Plant Lead Balance for 125% of design plant operating rate

Natural Gas Combustion

5.00E-04	lb lead/MMSCF natural gas	from EPA AP-42 Natural Gas Combustion
1.02E+03	BTU/SCF natural gas HHV	from EPA AP-42 Natural Gas Combustion
4.90E-07	lb lead /MMBTU HHV natural gas	calculated

SNG Combustion

Lead in Solids Feed to Gasifiers:

21.36	ppm dry lead is average reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 46A
167.17	ppm dry lead is maximum reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 46A

	Total stph dry	**Lead max ppm, dry**	**Lead max lb/hr**
Coal:	433.38	167.17	144.89
Coke:	0.00	0.5	
Total coal + coke	433.38		144.89

Output streams:	**max lead**	
Slag	33%	lead in gasifier feed goes out in slag per LGTI Gasification Plant metal mass balances (2002 IGCC Environmental Assessment by SAIC & NETL)
	47.82	lb/hr lead in slag
SNG	2.90E-06	lb/MMBTU HHV SNG based on LGTI Gasification Plant metal mass balances (2002 IGCC Environmental Assessment by SAIC & NETL)
	6,293	MMBTU/hr HHV SNG rate
	0.0182	lb/hr lead in SNG
Accumulation	97.06	lb/hr lead accumulated on shift catalyst, sulfided carbon beds, sulfur guard beds, methanation catalyst, and liquid filters

Coal Particulate Emissions	1.45	lb/hr coal dust from Coal Conveying, Storage and Feed Bins Dust Control System Vents
	2.42E-04	lb/hr lead in coal dust from coal converying, storage and feed bins dust control system vents
	2.12	lb/yr lead in coal dust from coal conveying and feed bins dust control system vents
	10.39	tons per year coal dust from coal unloading and storage
	3.47	lb/yr lead in coal dust from coal unloading and storage
	0.44	tons per year coal dust from rod mills
	0.15	lb/yr lead in coal dust from rod mills

Solid particulates Emission rate:

Emission Point Source	**cfm**	**dscfm**	**Emission Rate, lb/hr**
11a	30,000	33,760	1.4469
11b (spare)	30,000	33,760	

Notes:

Note 1: All sources (Coal & Coke Dust Collectors) will be fabric filter units with exhaust fans and will be specified to have a dust emissions limit, as measured in gr/dscf, equal to: 0.005 grains per drscf

FLARE SOURCES

NAME Hydrocarbon / Gasifier Start-up Flare

Unit ID: 001

STACK DATA

HEIGHT 300 ft
DIAMETER 6 ft

EMISSIONS: Scenario 1: Gasifier Start-Up Syngas Flaring

hr/yr = 135
Firing Rate = 861.7 MMBtu/hr
CO DRE 99.5 %

Pollutant	H2S in Syngas lb-mol/hr	COS in Syngas lb-mol/hr	Raw Syngas Flared lb-mol/hr	CO in Syngas Mol %	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	--	--	--	--	6.42	6.42	0.43
$PM_{2.5}$					6.02	6.02	0.41
SO_2	0.01	0	--	--	0.70	0.70	0.047
NOx	--	--	--	--	86.17	86.17	5.82
CO	--	--	18237.12	13.50	344.70	344.70	23.27
H2S (TAP)	0.01	--	--	--	0.01	0.01	0.00
COS (TAP)(VOC)	--	0.00	--	--	0.00	0.00	0.00
Other VOC	--	--	--	--	0.09	0.09	0.01
Total VOC					0.09	0.09	0.01

EMISSIONS: Scenario 2: Gasifier Start-Up Flare Pilot Burners Operating

hr/yr = 8,760
Pilot Firing Rate = 0.27 MMBtu/hr
AP-42 Heating Value = 1,020 Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.0020	0.0020	0.0087
$PM_{2.5}$	0.0019	0.0019	0.0081
SO_2	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.06
VOC	0.005	0.005	0.02
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

TOTAL STARTUP FLARING AND PILOT

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.101	6.42	0.44
$PM_{2.5}$	0.095	6.02	0.41
SO_2	0.01	0.70	0.048
NOx	1.38	86.22	6.05
CO	5.33	344.71	23.33
H2S (TAP)	0.005	0.01	0.02
COS (TAP)(VOC)	0.00	0.00	0.00
Total VOC	0.0067	0.09	0.03
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06

Calculations:

Scenario 1:

Emissions (SO2)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) + COS in Syngas (lb-mol/hr) X 64.063 lb/mol
Emissions (CO)(Avg. lb/hr)=(Raw Syngas flared (lbmols/hr) X CO in Syngas (mol %)/100) X 28.01 lb/mol X (100 - CO DRE)/100
Emissions (H2S)(Avg. lb/hr)=H2S in Syngas (lb-mol/hr) X 34.08 lb/mol X 2/100
Emissions (COS)(Avg. lb/hr)=COS in Syngas (lb-mol/hr) X 60.0764 lb/mol X 2/100
Emissions (NOx, PM_{10}, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenarios 2 and 3:

Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions-Pilot Case (SO2, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Scenario 1	NOx	PM_{10}	VOC
Factor (lb/MMBtu)	0.100	0.007	0.0001

Sources: NOx and PM_{10} for Syngas are based on values from vendor supplied data. VOC for Syngas = 2% of AP-42 Section 1.4 "Natural Gas Combustion" Table 1.4-2

Scenario 2	PM_{10}	SO_2
Factor (lb/MMscf)	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Scenario 2	NOx	CO	VOC
Factor (lb/MMBtu)	0.200	0.050	0.020

Sources: NOx and CO, and VOC are based on values from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

DRE for H2S and COS is considered as 98%.
DRE for CO is considered as 99.5%.
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs for natural gas to the pilot are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4. Flared gas is primarily CO and H2 - HAPs assumed negligable.
Scenario 1: Gasifier Start-up Syngas Flaring
Scenario 2: Gasifier Start-up Flare Pilot Burners Operating
Scenario 3: Normal Operations-Purge Gas and Pilot Gas Flaring

Number Shutdown Flaring Events / year = 15
Flaring Event Duration (hrs) = 3
Firing Rate (MMBtu/Event) = 34.26

SHUTDOWN FLARING

Pollutant	Average Emissions lb/event	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.260	0.09	0.002
$PM_{2.5}$	0.260	0.09	0.002
SO_2	255.62	85.21	1.917
NOx	3.43	1.14	0.026
CO	21.22	7.07	0.159
H2S (TAP)	2.660	0.89	0.020
COS (TAP)(VOC)	0.20	0.07	0.002
VOC	0.0037	0.00	0.000

GHG Emissions from Gasifier Start-up

The feed to the gasifier flare during the start-up of a gasifier contains CO and CO2, but no other carbon compounds. A mass balance was used to determine the CO2 and N2O emissions. There will be no CH4 emissions. The GHG Subpart Y (Refinery) flare equations are not applicable; however, the Subpart Y equation for N2O will be used to conservatively estimate N2O emissions.

	lb/hr	TPY	MT/yr
CO2 for Gasifier Flare =	185,818.1	12,542.7	11378.8

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF}\right)$$

Equation Y-5

N_2O = Annual nitrous oxide emissions from flared gas (metric ton N_2O/year)

CO_2 = Emission rate of CO_2 from flared gas calculated (metric ton/year)

EmF_{N2O} = Default N_2O emission factor for “Petroleum Products” from Table C-2 of subpart C (General Stationary Fuel Combustion Sources) (kg N_2O/MMBtu) = 0.0006

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

N2O for Gasifier Flare = 0.114 MT

GHG Emissions from Pilot

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123.2 MT

$$CH_4 \, or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Hydrocarbon / Gasifier Start-up Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

Startup

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	11,379	1	11,379		
CH4	0	21	0		
N2O	0.114	310	35.3		
		TOTAL =	11,414	12,578	TPY CO2

Shutdown

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	569	1	569		
CH4	0	21	0		
N2O	0.006	310	1.8		
		TOTAL =	571	629	TPY CO2

Shutdown flared gas volume on an annual basis is 5% of startup flared gas volume.

Pilot

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	123.2	1	123.2		
CH4	0.0023	21	0.05		
N2O	0.0002	310	0.07		
		TOTAL =	123.3	136	TPY CO2

FLARE SOURCES

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NAME Acid Gas Flare

Unit ID: 002

The Acid Gas Flare normally operates on pilot gas (natural gas) only. During an upset, acid gases can be routed to this flare.

STACK DATA

HEIGHT	300 ft
DIAMETER	1.6 ft

EMISSIONS: Acid Gas Flare Pilot Only

hr/yr =	8,760	
Pilot Firing Rate =	0.27	MMBtu/hr
AP-42 Heating Value =	1,020	Btu/scf

Pollutant	Average Emissions lb/hr	Maximum Emissions lb/hr	Annual Emissions TPY
PM_{10}	0.0020	0.0020	0.0087
$PM_{2.5}$	0.0019	0.0019	0.0081
SO_2	0.0002	0.0002	0.00068
NOx	0.053	0.053	0.23
CO	0.013	0.013	0.058
VOC	0.005	0.005	0.023
Total VOC HAPs	0.0005	0.0005	0.0022
Mercury (HAP)	4.4E-07	4.4E-07	1.9E-06
CO2	31.00	31.00	136

Calculations:
Emissions (PM10, SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion Factor (lb/MMscf)	PM_{10}	SO_2
	7.600	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for PM10.

Flare Factor (lb/MMBtu)	NOx	CO	VOC	CO2
	0.200	0.050	0.020	116.890

Source: NOx, CO, and VOC factors from AP-42 Section 13.5 "Industrial Flares" Table 13.5-1

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:
SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 123 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0023 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Acid Gas Flare	Volume of the gaseous fuel combusted	Annual	2,277,600	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	123	1	123		
CH4	0.0	21	0		
N2O	0.0	310	0		
		TOTAL =	123	136	TPY CO2

NAME Auxiliary Boiler

Unit ID: 005A & B

Emissions shown are for sum of two (2) boilers each at 408 MMBtu/hr

STACK DATA

HEIGHT	200	ft
DIAMETER	11	ft
GAS EXIT TEMP- Full rate - Natural Gas	310	°F
GAS EXIT TEMP- Full rate (Black Start) - Natural Gas	310	°F
GAS EXIT VELOCITY - Full rate - Natural Gas	48.73	fps
GAS EXIT VELOCITY - Full rate (Black Start) - Natural Gas	48.73	fps

COMBUSTION DATA

HEAT INPUT - Full rate - Natural Gas	816.33	MM Btu/hr
HEAT INPUT - Full rate (Black Start) - Natural Gas	816.33	MM Btu/hr
HEAT INPUT - Pilot Gas - Natural Gas	10.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS- Full rate - Natural Gas	1752	hr/yr
OPERATING HOURS - Full rate (Black Start) - Natural Gas	96	hr/yr

EMISSIONS: Full rate case - Natural Gas

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	6.08	6.08	5.33
$PM_{2.5}$	6.08	6.08	5.33
SO_2	0.48	0.48	0.42
NOx	10.20	10.20	8.94
CO	29.39	29.39	25.74
VOC	4.40	4.40	3.86
Total VOC HAPs	1.51	1.51	1.32
Mercury (HAP)	1.4E-03	1.4E-03	1.2E-03

EMISSIONS: Full rate (Black Start) case - Natural Gas

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	6.08	6.08	0.29
$PM_{2.5}$	6.08	6.08	0.29
SO_2	0.48	0.48	0.023
NOx	10.20	10.20	0.49
CO	29.39	29.39	1.41
VOC	4.40	4.40	0.21
Total VOC HAPs	1.51	1.51	0.073
Mercury (HAP)	1.4E-03	1.4E-03	6.6E-05

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	1.28	6.08	5.62
$PM_{2.5}$	1.28	6.08	5.62
SO_2	0.10	0.48	0.44
NOx	2.15	10.20	9.43
CO	6.20	29.39	27.15
VOC	0.93	4.40	4.07
Total VOC HAPs	0.32	1.51	1.40
Mercury (HAP)	2.9E-04	1.4E-03	1.3E-03

CALCULATIONS

Emissions (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Total Emissions (Avg. lb/hr) = Total TPY x 2,000 lb/ton / 8,760 hr/yr
Total Emissions (Max. lb/hr) = Highest Maximum lb/hr value from either case

Natural Gas Combustion	PM_{10}	VOC	SO_2	HAP
Factor (lb/MMscf)	7.600	5.50	0.60	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Natural Gas/SNG Combustion	NOx	CO
Factor (lb/MMBtu)	0.0125	0.036

Source: Emission factors for NOx and CO are based on vendor data for Low NOx burners (LNB), SCR and Flue Gas Recirculation.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.
To be conservative, SO2 emissions will be calculated assuming all scenarios fire natural gas. If SNG is fired, there will be no SO2 emissions as SNG is assumed to contain no sulfur.
To be conservative, the mercury factor for SNG (Coal-Coke) will be used for all cases.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 79,985 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 1.5086 MT
N2O = 0.1509 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Auxiliary Boiler	Volume of the gaseous fuel combusted	Annual	1,479,000,509	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	79,985	1	79,985		
CH4	1.5	21	32		
N2O	0.2	310	47		
		TOTAL =	80,063	88,230	TPY CO2

NAME AGR CO2 Regenerative Thermal Oxidizer

Unit ID: 007

There are 2 RTOs which share a common chimney (although there are separate stacks), and receive waste gas feeds from the Acid Gas Removal Unit.

Emissions are calculated for both cases (coal / coke and coal only) and the higher (conservative) value for each pollutant will be permitted.

STACK DATA

HEIGHT	200	ft
DIAMETER	9	ft
GAS EXIT TEMP	250	°F
GAS EXIT VELOCITY	60.5	fps

COMBUSTION DATA (max from either case)

HEAT INPUT: Two Units at full rate	77.62	MM Btu/hr
HEAT INPUT: One Unit at full rate	38.81	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	19.41	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8298	hr/yr
OPERATING HOURS: One Unit at full rate	438	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.57	lb/hr
COS in Waste gas to each RTO =	2.00	lb/hr
CO in Waste gas to each RTO:	4673.99	lb/hr
Total Sulfur in Waste gas to each RTO:	1.60	lb/hr
Methanol in Waste Gas to each RTO:	80.20	lb/hr
H2S and COS DRE:	98	%
CO and Methanol DRE:	99	%

EMISSIONS: Two Units at Full Rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.58	0.58	2.40
$PM_{2.5}$	0.58	0.58	2.40
SO_2	6.33	6.33	26.27
NOx	3.95	3.95	16.41
CO	96.27	96.27	399.44
VOC	2.10	2.10	8.72
H2S (TAP)	0.02	0.02	0.09
COS (HAP)(VOC)	0.08	0.08	0.33
Methanol (HAP)(VOC)	1.60	1.60	6.66
Total VOC HAPs	1.83	1.83	7.58
Mercury (HAP)	1.2E-04	1.2E-04	5.2E-04

EMISSIONS: Two Units on Hot Standby

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.29	0.29	0.06
$PM_{2.5}$	0.29	0.29	0.06
SO_2	3.17	3.17	0.69
NOx	1.98	1.98	0.43
CO	48.14	48.14	10.54
VOC	1.05	1.05	0.23
H2S (TAP)	0.01	0.01	0.00
COS (HAP)(VOC)	0.04	0.04	0.01
Methanol (HAP)(VOC)	0.80	0.80	0.18
Total VOC HAPs	0.91	0.91	0.20
Mercury (HAP)	6.2E-05	6.2E-05	1.4E-05

EMISSIONS: One Unit at half rate - Conservatively assume Natural Gas for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.14	0.14	0.0017
PM$_{2.5}$	0.14	0.14	0.0017
SO$_2$	1.58	1.58	0.019
NOx	0.99	0.99	0.012
CO	24.07	24.07	0.29
VOC	0.53	0.53	0.006
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.0002
Methanol (HAP)(VOC)	0.40	0.40	0.0048
Total VOC HAPs	0.46	0.46	0.005
Mercury (HAP)	3.1E-05	3.1E-05	3.7E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.56	0.58	2.46
PM$_{2.5}$	0.56	0.56	2.46
SO$_2$	6.16	6.33	26.98
NOx	3.85	3.95	16.85
CO	93.67	96.27	410.27
VOC	2.05	2.10	8.96
H2S (TAP)	0.022	0.02	0.10
COS (HAP)(VOC)	0.08	0.08	0.34
Methanol (HAP)(VOC)	1.56	1.60	6.84
Total VOC HAPs	1.78	1.83	7.79
Mercury (HAP)	1.2E-04	1.2E-04	5.3E-04

CALCULATIONS

Emissions (PM$_{10}$) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions - Normal (SO2) (Avg. lb/hr) = S in Waste Gas to each RTO (lb/hr) X 2 X DRE/100 X Mw SO2 (lb/lb-mol) / Mw S (lb/lb-mol)

Emissions - Black-start (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions (NOx) (Avg. lb/hr) = Vendor Factor (lb/MMBtu) X Heat Input (MMBtu/hr)

Emissions (CO) (Avg. lb/hr) = Vendor Factor (lb/MMBtu) X Heat Input (MMBtu/hr) + CO in Waste Gas (lb/hr) X 2 X (1 - DRE)/100

Emissions (VOC) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr) + COS (lb/hr) + MeOH (lb/hr)

Emissions (COS, MeOH) (Avg. lb/hr) = lb in Waste Gas (lb/hr) X 2 X (1 - DRE)/100

Emissions for each Case (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Maximum Emissions for each Case (lb/hr) = Average Emissions

Emissions TPY Total = Sum of individual cases

Emissions (Avg. lb/hr) Total = TPY Total X 2,000 (lb/T) / (Total Hrs Operation)

Natural Gas Combustion	PM$_{10}$	VOC	SO$_2$	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM$_{10}$

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtuf)	0.05	0.036

Source: Emission factors for NOx and CO are based on information from vendor supplied data and the use of Low NOx burners.

Comments:

SO$_2$ emissions based on 98% conversion of sulfur in waste gas to SO$_2$. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).

During "normal operations" the thermal oxidizer burns SNG (which contains no sulfur); during a black-start, it fires natural gas for the first 4 hours. Permitted emissions will conservatively be based on firing natural gas only.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

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Coal / Coke Case

COMBUSTION DATA

HEAT INPUT: Two Units at full rate	62.69	MM Btu/hr
HEAT INPUT: One Unit at full rate	31.35	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	15.67	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8298	hr/yr
OPERATING HOURS: One Unit at full rate	438	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.56	lb/hr
COS in Waste gas to each RTO =	1.97	lb/hr
CO in Waste gas to each RTO:	4595.57	lb/hr
Total Sulfur in Waste gas to each RTO:	1.58	lb/hr
Methanol in Waste Gas to each RTO:	78.86	lb/hr
H2S and COS DRE:	98	%
CO and Methanol DRE:	99	%

EMISSIONS: Two Units at Full Rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.47	0.47	1.94
SO_2	6.22	6.22	25.80
NOx	3.19	3.19	13.25
CO	94.17	94.17	390.70
VOC	1.99	1.99	8.27
H2S (TAP)	0.02	0.02	0.09
COS (HAP)(VOC)	0.08	0.08	0.33
Methanol (HAP)(VOC)	1.58	1.58	6.54
Total HAPs	1.77	1.77	7.35
Mercury (HAP)	1.1E-04	1.1E-04	4.4E-04

EMISSIONS: One Unit at full rate

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.23	0.23	0.05
SO_2	3.11	3.11	0.681
NOx	1.60	1.60	0.35
CO	47.08	47.08	10.31
VOC	1.00	1.00	0.22
H2S (TAP)	0.01	0.01	0.002
COS (HAP)(VOC)	0.04	0.04	0.01
Methanol (HAP)(VOC)	0.79	0.79	0.17
Total HAPs	0.89	0.89	0.19
Mercury (HAP)	5.3E-05	5.3E-05	1.2E-05

EMISSIONS: One Unit at half rate - Conservatively assume Natural Gas (for SO2) and SNG (for Hg) for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.12	0.12	0.0014
SO_2	1.55	1.55	0.019
NOx	0.80	0.80	0.010
CO	23.54	23.54	0.28
VOC	0.50	0.50	0.0060
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.00024
Methanol (HAP)(VOC)	0.39	0.39	0.0047
Total HAPs	0.44	0.44	0.0053
Mercury (HAP)	2.6E-05	2.6E-05	3.2E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.45	0.47	1.99
SO_2	6.05	6.22	26.50
NOx	3.11	3.19	13.61
CO	91.62	94.17	401.30
VOC	1.94	1.99	8.50
H2S (TAP)	0.02	0.02	0.10
COS (HAP)(VOC)	0.08	0.08	0.34
Methanol (HAP)(VOC)	1.53	1.58	6.72
Total HAPs	1.72	1.77	7.55
Mercury (HAP)	1.0E-04	1.1E-04	4.5E-04

Natural Gas Combustion	PM_{10}	VOC	SO_2	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM_{10}

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.05	0.036

	Natural Gas	SNG
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 9,711 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.1832 MT
N2O = 0.0183 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Coal / Coke Case	Volume of the gaseous fuel combusted	Annual	179,564,678	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	9,711	1	9,711
CH4	0.18	21	4
N2O	0.018	310	6
		TOTAL =	9,720

10,712 TPY CO2

Feeds to RTO (CO2 + combusted CO):

1,427,034 lb/hr at full rate per Eng. Design
20% percent of max vented per year.
1,250,082 tons/yr

1,134,067 MTCO2e 1,250,082 Subtotal TPY CO2

Total CO2e: 1,143,784 MTCO2e 1,260,793 Total TPY CO2e

Coal Only Case

COMBUSTION DATA

HEAT INPUT: Two Units at full rate	77.62	MM Btu/hr
HEAT INPUT: One Unit at full rate	38.81	MM Btu/hr
HEAT INPUT: Black-starts (1 unit at half rate)	19.41	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS: Two Units at full rate	8298	hr/yr
OPERATING HOURS: One Unit at full rate	438	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
H2S in Waste gas to each RTO =	0.57	lb/hr
COS in Waste gas to each RTO =	2.00	lb/hr
CO in Waste gas to each RTO:	4673.99	lb/hr
Total Sulfur in Waste gas to each RTO:	1.60	lb/hr
Methanol in Waste Gas to each RTO:	80.20	lb/hr
H2S and COS DRE:	98	%
CO and Methanol DRE:	99	%

EMISSIONS: Two Units at Full Rate (100%)

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.58	0.58	2.40
SO$_2$	6.33	6.33	26.27
NOx	3.95	3.95	16.41
CO	96.27	96.27	399.44
VOC	2.10	2.10	8.72
H2S (TAP)	0.02	0.02	0.09
COS (HAP)(VOC)	0.08	0.08	0.33
Methanol (HAP)(VOC)	1.60	1.60	6.66
Total HAPs	1.83	1.83	7.58
Mercury (HAP)	1.2E-04	1.2E-04	5.2E-04

EMISSIONS: One Unit at full rate

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.29	0.29	0.06
SO$_2$	3.17	3.17	0.69
NOx	1.98	1.98	0.43
CO	48.14	48.14	10.54
VOC	1.05	1.05	0.23
H2S (TAP)	0.01	0.01	0.002
COS (HAP)(VOC)	0.04	0.04	0.01
Methanol (HAP)(VOC)	0.80	0.80	0.18
Total HAPs	0.91	0.91	0.20
Mercury (HAP)	6.2E-05	6.2E-05	1.4E-05

EMISSIONS: One Unit at half rate (25%) - Conservatively assume Natural Gas (for SO2) and SNG (for Hg) for entire 24 hrs

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.14	0.14	0.0017
SO_2	1.58	1.58	0.019
NOx	0.99	0.99	0.012
CO	24.07	24.07	0.29
VOC	0.53	0.53	0.0063
H2S (TAP)	0.01	0.01	0.0001
COS (HAP)(VOC)	0.02	0.02	0.0002
Methanol (HAP)(VOC)	0.40	0.40	0.0048
Total HAPs	0.46	0.46	0.0055
Mercury (HAP)	3.1E-05	3.1E-05	3.7E-07

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.56	0.58	2.46
SO_2	6.16	6.33	26.98
NOx	3.85	3.95	16.85
CO	93.67	96.27	410.27
VOC	2.05	2.10	8.96
H2S (TAP)	0.022	0.02	0.10
COS (HAP)(VOC)	0.08	0.08	0.34
Methanol (HAP)(VOC)	1.56	1.60	6.84
Total HAPs	1.78	1.83	7.79
Mercury (HAP)	1.2E-04	1.2E-04	5.3E-04

Natural Gas Combustion	PM_{10}	VOC	SO_2	HAP
Factor (lb/MM scf)	7.60	5.50	0.6	1.89

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM_{10}

Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.05	0.036

	Natural Gas	SNG
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 10,976 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.2070 MT
N2O = 0.0207 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Coal Only Case	Volume of the gaseous fuel combusted	Annual	202,961,074	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	10,976	1	10,976
CH4	0.21	21	4
N2O	0.021	310	6
		TOTAL =	10,987

12,108 TPY CO2

Feeds to RTO (CO2 + combusted CO): 1,458,491 lb/hr at full rate per Eng. Design
20% percent of max vented per year.
1,277,638 tons/yr

1,159,066 MTCO2e 1,277,638 subtotal TPY CO2

Total CO2e: 1,170,050 MTCO2e 1,289,746 Total TPY CO2e

Max CO2e: 1,170,050 MT/yr

NAME Gasifier Start-up Preheat Burner A

Unit ID: 008 A

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	1168	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0078
$PM_{2.5}$	0.013	0.013	0.0073
SO_2	0.011	0.011	0.0062
NOx	1.800	1.800	1.05
CO	1.008	1.008	0.59
VOC	0.097	0.097	0.057
Total VOC HAPs	0.033	0.033	0.019
Mercury (HAP)	3.0E-05	3.0E-05	1.8E-05

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 1,168 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0220 MT
N2O = 0.0022 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner A	Volume of the gaseous fuel combusted	Annual	21,600,000	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	1,168	1	1,168
CH4	0.0	21	0
N2O	0.0	310	1
		TOTAL =	1,169

1,289 TPY CO2

NAME Gasifier Start-up Preheat Burner B

Unit ID: 008 B

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	1168	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0078
$PM_{2.5}$	0.013	0.013	0.0073
SO_2	0.011	0.011	0.0062
NOx	1.800	1.800	1.05
CO	1.008	1.008	0.59
VOC	0.097	0.097	0.057
Total VOC HAPs	0.033	0.033	0.019
Mercury (HAP)	3.0E-05	3.0E-05	1.8E-05

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 1,168 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0220 MT
N2O = 0.0022 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner B	Volume of the gaseous fuel combusted	Annual	21,600,000	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	1,168	1	1,168		
CH4	0.0	21	0		
N2O	0.0	310	1		
		TOTAL =	1,169	1,289	TPY CO2

NAME Gasifier Start-up Preheat Burner C

Unit ID: 008 C

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	1168	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.013	0.013	0.0078
PM$_{2.5}$	0.013	0.013	0.0073
SO$_2$	0.011	0.011	0.0062
NOx	1.800	1.800	1.05
CO	1.008	1.008	0.59
VOC	0.097	0.097	0.057
Total VOC HAPs	0.033	0.033	0.019
Mercury (HAP)	3.0E-05	3.0E-05	1.8E-05

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM$_{10}$	0.026	0.026	0.00038
PM$_{2.5}$	0.024	0.024	0.00035
SO$_2$	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)

Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion Factor (lb/MM scf)	SO$_2$
	0.6

Natural Gas Combustion Factor (lb/MM Btu)	PM$_{10}$	NOx	CO	VOC
	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).

Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 1,168 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0220 MT
N2O = 0.0022 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner C	Volume of the gaseous fuel combusted	Annual	21,600,000	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	1,168	1	1,168
CH4	0.0	21	0
N2O	0.0	310	1
		TOTAL =	1,169

1,289 TPY CO2

NAME Gasifier Start-up Preheat Burner D

Unit ID: 008 D

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	1168	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0078
$PM_{2.5}$	0.013	0.013	0.0073
SO_2	0.011	0.011	0.0062
NOx	1.800	1.800	1.05
CO	1.008	1.008	0.59
VOC	0.097	0.097	0.057
Total VOC HAPs	0.033	0.033	0.019
Mercury (HAP)	3.0E-05	3.0E-05	1.8E-05

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 1,168 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0220 MT
N2O = 0.0022 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner D	Volume of the gaseous fuel combusted	Annual	21,600,000	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	1,168	1	1,168		
CH4	0.0	21	0		
N2O	0.0	310	1		
		TOTAL =	1,169	1,289	TPY CO2

NAME Gasifier Start-up Preheat Burner E

Unit ID: 008 E

STACK DATA

HEIGHT	150	ft
DIAMETER	4	ft
GAS EXIT TEMP	232	°F
GAS EXIT VELOCITY: Normal Ops	65.00	fps
GAS EXIT VELOCITY: Black Start	126.39	fps

COMBUSTION DATA

HEAT INPUT: Normal Ops	18.00	MM Btu/hr
HEAT INPUT: Black Start	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1020	Btu/ft^3
OPERATING HOURS -Normal Case	1168	hr/yr
OPERATING HOURS -Black Starts	28.8	hr/yr

EMISSIONS: Normal Case

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.013	0.013	0.0078
$PM_{2.5}$	0.013	0.013	0.0073
SO_2	0.011	0.011	0.0062
NOx	1.800	1.800	1.05
CO	1.008	1.008	0.59
VOC	0.097	0.097	0.057
Total VOC HAPs	0.033	0.033	0.019
Mercury (HAP)	3.0E-05	3.0E-05	1.8E-05

EMISSIONS: Black Starts

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.026	0.026	0.00038
$PM_{2.5}$	0.024	0.024	0.00035
SO_2	0.021	0.021	0.00030
NOx	3.500	3.500	0.05
CO	1.960	1.960	0.0282
VOC	0.189	0.189	0.00272
Total VOC HAPs	0.065	0.065	0.00093
Mercury (HAP)	6.8E-06	6.8E-06	9.8E-08

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (PM10, NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.6

Natural Gas Combustion	PM_{10}	NOx	CO	VOC
Factor (lb/MM Btu)	0.0007	0.100	0.056	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 1,168 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0220 MT
N2O = 0.0022 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Gasifier Start-up Preheat Burner E	Volume of the gaseous fuel combusted	Annual	21,600,000	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	1,168	1	1,168		
CH4	0.0	21	0		
N2O	0.0	310	1		
		TOTAL =	1,169	1,289	TPY CO2

NAME Emergency Diesel Power Generator A Unit ID: 009 A

COMBUSTION DATA

FUEL TYPE	Diesel	
ENGINE SIZE	1,341	HP
HOURS OF OPERATION	52	hr/yr

EMISSIONS

		avg lb/hr	lb/hr max.	TPY
PM_{10}		0.06	0.06	0.0015
$PM_{2.5}$		0.06	0.06	0.0014
SO_2		0.015	0.015	0.00039
NO_X		14.58	14.58	0.38
CO		0.38	0.38	0.010
VOC	(TOC)	0.03	0.03	0.00077

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

	PM_{10}	SO_2	NO_X	CO	VOC
Diesel Industrial Engine Factors (Lb/hp-hr)	4.4E-05	1.1E-05	0.0109	2.9E-04	2.2E-05

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 22.1 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.00090 MT
N2O = 0.000179 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Emergency Diesel Power Generator A	Gallons of diesel fuel combusted	Annual	2,163	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	22.1	1	22.1
CH4	0.00090	21	0.0188
N2O	0.000179	310	0.056
		TOTAL =	22.2

24.4 TPY CO2

Fuel Consumption 50% load = 20.8 gal/hr.
Assumed Fuel at 100% Load = 41.6 gal/hr.

NAME Emergency Diesel Power Generator B Unit ID: 009 B

COMBUSTION DATA

FUEL TYPE	Diesel
ENGINE SIZE	1,341 HP
HOURS OF OPERATION	52 hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.06	0.06	0.0015
$PM_{2.5}$	0.06	0.06	0.0014
SO_2	0.015	0.015	0.00039
NO_X	14.58	14.58	0.38
CO	0.38	0.38	0.010
VOC (TOC)	0.03	0.03	0.00077

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

	PM_{10}	SO_2	NO_X	CO	VOC
Diesel Industrial Engine Factors (Lb/hp-hr)	4.4E-05	1.1E-05	0.0109	2.9E-04	2.2E-05

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS

ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 11.0 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$ Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.00045 MT
N2O = 0.000090 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Emergency Diesel Power Generator B	Gallons of diesel fuel combusted	Annual	1,082	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	11.0	1	11.0
CH4	0.00045	21	0.0094
N2O	0.000090	310	0.028
		TOTAL =	11.1

12.2 TPY CO2

Fuel Consumption 50% load = 20.8 gal/hr.
Assumed Fuel at 100% Load = 41.6 gal/hr.

NAME Fire Water Diesel Pump A

Unit ID: 010 A

COMBUSTION DATA

FUEL TYPE	Diesel	
ENGINE SIZE	575	HP
HOURS OF OPERATION	52	hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0028
$PM_{2.5}$	0.101	0.101	0.0026
SO_2	0.0061	0.0061	0.00016
NO_X	3.131	3.131	0.081
CO	0.799	0.799	0.021
VOC	0.218	0.218	0.0057

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 10 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0004 MT
N2O = 0.00009 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump A	Gallons of diesel fuel combusted	Annual	1,027	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	10.5	1	10.5
CH4	0.00043	21	0.0089
N2O	0.000085	310	0.026
		TOTAL =	10.5

11.6 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

NAME Fire Water Diesel Pump B

Unit ID: 010 B

COMBUSTION DATA

FUEL TYPE	Diesel
ENGINE SIZE	575 HP
HOURS OF OPERATION	52 hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0028
$PM_{2.5}$	0.101	0.101	0.0026
SO_2	0.0061	0.0061	0.00016
NO_X	3.131	3.131	0.081
CO	0.799	0.799	0.021
VOC	0.218	0.218	0.0057

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 4 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0002 MT
N2O = 0.00003 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump B	Gallons of diesel fuel combusted	Annual	411	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	4.2	1	4.2
CH4	0.00017	21	0.0036
N2O	0.000034	310	0.011
		TOTAL =	4.2

4.6 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

COMBUSTION SOURCES

NAME Fire Water Diesel Pump C

Unit ID: 010 C

COMBUSTION DATA

FUEL TYPE	Diesel
ENGINE SIZE	575 HP
HOURS OF OPERATION	52 hr/yr

EMISSIONS

	avg lb/hr	lb/hr max.	TPY
PM_{10}	0.108	0.108	0.0028
$PM_{2.5}$	0.101	0.101	0.0026
SO_2	0.0061	0.0061	0.00016
NO_X	3.131	3.131	0.081
CO	0.799	0.799	0.021
VOC	0.218	0.218	0.0057

CALCULATIONS:
Emissions (LB/HR) = Vendor Factor X HP
Emissions (TPY) = Emissions (LB/HR) X (Hours of operation/2000)

Diesel Industrial Engine Factors (Lb/hp-hr)	PM_{10}	SO_2	NO_X	CO	VOC
	1.9E-04	1.1E-05	0.0054	1.4E-03	3.8E-04

Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.
SO2 emissions based on 15 ppm S in diesel and 100% conversion to SO2.

COMMENTS
ASSUMED MAXIMUM HOURLY EMISSIONS EQUAL TO AVERAGE HOURLY EMISSIONS.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
HAPs emission from this limited use source assumed to be negligable

Stationary Combustion Sources - Diesel

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume) 0.138
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 73.96
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 4 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.003
0.0006
1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0002 MT
N2O = 0.00003 MT

Emission Points	Data Required	MRR Frequency	Data	Units
Fire Water Diesel Pump C	Gallons of diesel fuel combusted	Annual	411	Gallons
	High heat value of the fuel from all valid samples for the year	Annual Average	0.13800	MMBtu per gal

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	4.2	1	4.2
CH4	0.00017	21	0.0036
N2O	0.000034	310	0.011
		TOTAL =	4.2

4.6 TPY CO2

Fuel Consumption 40% load = 7.9 gal/hr.
Assumed Fuel at 100% Load = 19.75 gal/hr.

VENT SOURCES

The following are the vent sources related to solids handling, including coke and coal. These sources are all controlled by baghouses.

Source 011 B is a spare for source 011 A. Only one of these two sources will be in operation at one time.

PM_{10} EMISSIONS		Exhaust Air Flow per filter	Filter PM10 Performance	Average Emissions	Maximum Hourly	Annual PM_{10} Emissions	Annual $PM_{2.5}$ Emissions
Unit ID	Name	dscfm	gr/dscf	lb/hr	lb/hr	TPY	TPY
011 A	System 1A -- Coal-Coke Handling System	33,760	0.003	0.868	0.868	3.80	1.86
011 B	System 1B -- Coal-Coke Handling System (Spare)						

Comments:

Outlet grain loading factor (gr/acfm) 0.003 gr/dscf PM/PM10, 0.0015 gr/dscf PM2.5.

VENT SOURCES

The following are the sources related to solids unloading (barge and rail car) and handling, including coke and coal piles.

Height of Piles 90 ft
Diameter of Piles 539 ft

PM$_{10}$ EMISSIONS		Process Rate		Emission Factor		Control Type	Control Efficiency	Operating Hours	Average Emissions	Maximum Hourly	Annual Emissions	Factor PM Total/	Total PM Emissions (Calc. here) Average Emissions	Maximum Hourly	Annual Emissions
Unit ID	Name								lb/hr	lb/hr	TPY		lb/hr	lb/hr	TPY
012 A	Barge Unload to Hopper	750	TPH	0.00056	lb/ton	WET SUPPRESSION	85.0%	2,678	0.063	0.063	0.084	2.114	0.13	0.13	0.18
012 B	Barge Unload Hopper to Belt	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,678	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 C	Barge Conveyor Transfer Drop	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,678	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 D	Barge Conveyor Transfer Drop	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,678	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 E	Barge Conveyor Transfer Drop	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,678	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 F	Barge Conveyor Transfer Drop	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,678	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 G	Rail Unload 1 to Hopper	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	663	0.039	0.039	0.013	Note 2	0.039	0.039	0.013
012 H	Rail Unload 2 to Hopper	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	663	0.039	0.039	0.013	Note 2	0.039	0.039	0.013
012 I	Rail Unload Hopper 1 to Belt	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	663	0.039	0.039	0.013	Note 2	0.039	0.039	0.013
012 J	Rail Unload Hopper 2 to Belt	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	663	0.039	0.039	0.013	Note 2	0.039	0.039	0.013
012 K	Rail Unload Belts 1 & 2 to Stacker Belt 1	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	663	0.039	0.039	0.013	Note 2	0.039	0.039	0.013
012 L	Stacker Belt 1 to Radial Stacker (Pile1)	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,002	0.039	0.039	0.039	Note 2	0.039	0.039	0.039
012 M	Stacker Belt 2 from Radial Stacker (Pile 1)	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,002	0.039	0.039	0.039	Note 2	0.039	0.039	0.039
012 N	Radial Stacker to Pile 1	3,000	TPH	0.00056	lb/ton	FABRIC FILTERS w/TELESCOPING CHUTE	99.9%	2,002	0.002	0.002	0.002	Note 2	0.002	0.002	0.002
012 O	Radial Stacker to Pile 2	3,000	TPH	0.00056	lb/ton	FABRIC FILTERS w/TELESCOPING CHUTE	99.9%	2,002	0.002	0.002	0.002	Note 2	0.002	0.002	0.002
012 P	Dozer Activity on Pile 1	1,500	TPH	0.239	lb/hr	WET SUPPRESSION	90.0%	4,380	0.024	0.048	0.052	Note 1	0.11	0.22	0.24
012 Q	Dozer Activity on Pile 2	1,500	TPH	0.239	lb/hr	WET SUPPRESSION	90.0%	4,380	0.024	0.048	0.052	Note 1	0.11	0.22	0.24
012 R	Pile 1 / Bottom Hopper / Belt / Classification Tower	6,000	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,708	0.15	0.15	0.21	Note 2	0.15	0.15	0.21
012 S	Pile 2 / Bottom Hopper / Belt / Classification Tower	6,000	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,708	0.15	0.15	0.21	Note 2	0.15	0.15	0.21
012 T	CLASSIFICATION TOWER #1	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,708	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 U	CLASSIFICATION TOWER #2	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,708	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 V	Classification Towers to Day Bin	1,500	ACFM	2.50	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.88%	2,708	0.039	0.039	0.052	Note 2	0.039	0.039	0.052
012 W	Wind Erosion Pile 1	300,000	Tons	2.157	lb/hr	WET SUPPRESSION/COMPACTION	90.0%	8,760	0.22	0.22	0.94	2.0	0.43	0.43	1.89
012 X	Wind Erosion Pile 2	300,000	Tons	1.794	lb/hr	WET SUPPRESSION/COMPACTION	90.0%	8,760	0.18	0.18	0.79	2.0	0.36	0.36	1.57
									TOTAL PM10 =		2.90		TOTAL Particulate =		5.10

012 Y-AC on separate spreadsheet Tab

Comments:

Dozer activity (012 P and 012 Q) factors calculated based on equations from AP-42 Section 13.2.2
Transfer point (012 A, 012 N and 012 O) factors calculated based on equations from AP-42 Section 13.2.4
Coke / Coal pile (012 W and 012 X) wind erosion factors calculated based on equations from AP-42 Section 13.2.5
Inlet grain loading factor (gr/acfm) estimated by vendor, control efficiencies for filtered exhausts achieve 0.003 gr/dscf PM/PM10, 0.0015 gr/dscf PM2.5.

VENT SOURCES

PM$_{2.5}$ EMISSIONS		Process Rate		Emission Factor		Control Type	Control Efficiency	Operating Hours	Average Emissions	Maximum Hourly	Annual Emissions
Unit ID	Name								lb/hr	lb/hr	TPY
012 A	Barge Unload to Hopper	750	TPH	0.000084	lb/ton	WET SUPPRESSION	85.0%	2,678	0.0095	0.0095	0.013
012 B	Barge Unload Hopper to Belt	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,678	0.019	0.019	0.026
012 C	Barge Conveyor Transfer Drop	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,678	0.019	0.019	0.026
012 D	Barge Conveyor Transfer Drop	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,678	0.019	0.019	0.026
012 E	Barge Conveyor Transfer Drop	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,678	0.019	0.019	0.026
012 F	Barge Conveyor Transfer Drop	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,678	0.019	0.019	0.026
012 G	Rail Unload 1 to Hopper	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	663	0.019	0.019	0.006
012 H	Rail Unload 2 to Hopper	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	663	0.019	0.019	0.006
012 I	Rail Unload Hopper 1 to Belt	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	663	0.019	0.019	0.006
012 J	Rail Unload Hopper 2 to Belt	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	663	0.019	0.019	0.006
012 K	Rail Unload Belts 1 & 2 to Stacker Belt 1	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	663	0.019	0.019	0.006
012 L	Stacker Belt 1 to Radial Stacker (Pile1)	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,002	0.019	0.019	0.019
012 M	Stacker Belt 2 from Radial Stacker (Pile 1)	1,500	ACFM	0.175000	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,002	0.019	0.019	0.019
012 N	Radial Stacker to Pile 1	3,000	TPH	0.000084	lb/ton	FABRIC FILTERS w/TELESCOPING CHUTE	99.9%	2,002	0.00025	0.00025	0.00025
012 O	Radial Stacker to Pile 2	3,000	TPH	0.000084	lb/ton	FABRIC FILTERS w/TELESCOPING CHUTE	99.9%	2,002	0.00025	0.00025	0.00025
012 P	Dozer Activity on Pile 1	1,500	TPH	0.024	lb/hr	WET SUPPRESSION	90.0%	4,380	0.002	0.005	0.005
012 Q	Dozer Activity on Pile 2	1,500	TPH	0.024	lb/hr	WET SUPPRESSION	90.0%	4,380	0.002	0.005	0.005
012 R	Pile 1 / Bottom Hopper / Belt / Classification Tower	6,000	ACFM	0.18	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,708	0.077	0.077	0.10
012 S	Pile 2 / Bottom Hopper / Belt / Classification Tower	6,000	ACFM	0.18	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,708	0.077	0.077	0.10
012 T	CLASSIFICATION TOWER #1	1,500	ACFM	0.18	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,708	0.019	0.019	0.026
012 U	CLASSIFICATION TOWER #2	1,500	ACFM	0.18	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,708	0.019	0.019	0.026
012 V	Classification Towers to Day Bin	1,500	ACFM	0.18	GR/ACFM	DUST EXTRACTION SYSTEM or FILTER	99.14%	2,708	0.019	0.019	0.026
012 W	Wind Erosion Pile 1	300,000	Tons	0.229	lb/hr	WET SUPPRESSION/COMPACTION	90.0%	8,760	0.023	0.023	0.10
012 X	Wind Erosion Pile 2	300,000	Tons	0.190	lb/hr	WET SUPPRESSION/COMPACTION	90.0%	8,760	0.019	0.019	0.083

TOTAL PM10 = 0.70

Comments:

Dozer activity (012 P and 012 Q) factors calculated based on equations from AP-42 Section 13.2.2
Transfer point (012 A, 012 N and 012 O) factors calculated based on equations from AP-42 Section 13.2.4
Coke / Coal pile (012 W and 012 X) wind erosion factors calculated based on equations from AP-42 Section 13.2.5
Inlet grain loading factor (gr/acfm) estimated by vendor, control efficiencies for filtered exhausts achieve 0.003 gr/dscf PM/PM10, 0.0015 gr/dscf PM2.5.

VENT SOURCES

Basis of Factors to convert PM10 estimate to Total PM

Aggregate Handling Sources	
- Total PM Aerodynamic Particle Size Multiplier (k) from	0.74
- PM10 Aerodynamic Particle Size Multiplier (k) from AP	0.35
Factor to c	2.114
Wind Erosion From Piles	
- Total Particulate Factor for Alternative Method from WR	1.0
- PM10 factor for Alternative Method from WRAP docum	0.5
Factor to c	2.0

Note 1: Dozer (Unpaved Roadway) Sources
Dozer Total PM is calculated on separate worksheet page, "Total PM for Dozers" because
the calcualion involves more than a simple k factor (ie: exponents, etc)

Note 2: Fabric Filter controlled sources:
These sources have PM10 estimated using estimated design total particulate grain loading on the outlet.
All outlet PM is conservatively assumed to be PM10, therefore total PM = PM10.

NAME Rod Mill Air Eductors

STACK DATA

HEIGHT	125	ft
DIAMETER	0.5	ft
GAS EXIT TEMP	80	°F
GAS EXIT VELOCITY	15.46	fps
OPERATING HOURS	8,760	hr/yr

PM_{10} EMISSIONS	Average Emissions	Maximum Hourly	Annual PM_{10} Emissions	Annual $PM_{2.5}$ Emissions
Unit ID	lb/hr	lb/hr	TPY	TPY
013 A	0.025	0.025	0.11	0.032
013 C	0.025	0.025	0.11	0.032
013 C	0.025	0.025	0.11	0.032
013 D	0.025	0.025	0.11	0.032
Total	0.10	0.10	0.44	0.13

Emissions based on engineered equipment data

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

NAME Wet Sulfuric Acid (WSA) Unit Stack A

Unit ID: 015 A

Emissions of all pollutants are higher for the Coal / Coke Case.

STACK DATA

HEIGHT	200	ft
DIAMETER	4.83	ft
GAS EXIT TEMP	176	°F
GAS EXIT VELOCITY: Two Unit Operation	102.2	fps
GAS EXIT VELOCITY: One Unit Operation	51.1	fps
GAS EXIT VELOCITY: Black start	25.5	fps
GAS EXIT VELOCITY: Preheat	115.3	fps

COMBUSTION DATA

HEAT INPUT - Preheat	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
OPERATING HOURS: Two Unit Operation	8,298	hr/yr
OPERATING HOURS: One Unit Operation	438	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
OPERATING HOURS: Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	34.44
NOx	10.17	10.17	42.20
CO	18.72	18.72	77.69
H_2SO_4	5.00	5.00	20.73
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.91
NOx	5.09	5.09	1.11
CO	9.36	9.36	2.05
H_2SO_4	2.50	2.50	0.55
Mercury (HAP)	3.3E-10	3.3E-10	7.3E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
$PM_{2.5}$	0.02	0.02	0.0006
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.00018	0.03	0.0008
$PM_{2.5}$	0.00015	0.02	0.0006
SO_2	8.53	8.30	35.37
NOx	9.92	10.17	43.46
CO	18.23	18.72	79.85
VOC	0.0013	0.19	0.006
Total VOC HAPs	0.0004	0.06	0.0019
Mercury (HAP)	4.0E-07	6.5E-02	1.8E-06
H_2SO_4	4.86	5.00	21.29
$PM_{2.5}$ including H_2SO_4	4.86	5.00	21.29

CALCULATIONS

Emissions Preheat Case: (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions Preheat Case: (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)
Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

Source: Emission factors for NOx and CO are based on information from vendor supplied data.

Comments:

SO2 emissions for preheat case based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.
The emission rate data from the WSA Trains is based on information from process licensee.
Total WSA capacity for two trains is 136,658 lb/h of 97.5 wt% Sulfuric Acid production OR 1,599 stpd on dry basis (100% acid).
Burner flue gas is scrubbed in gasifier quench water to remove over 90% of particulate.

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Coal / Coke Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,298	hr/yr
Half Rate	438	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	34.44
NOx	10.17	10.17	42.20
CO	18.72	18.72	77.69
H_2SO_4	5.00	5.00	20.73
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.91
NOx	5.09	5.09	1.11
CO	9.36	9.36	2.05
H_2SO_4	2.50	2.50	0.55
Mercury (HAP)	3.3E-10	3.3E-10	7.1E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	3.9E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal-Coke)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	111	1	111		
CH4	0.0	21	0		
N2O	0.0	310	0		
		TOTAL =	111	123	TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	14538.1	lb-mole/hr		
CO2% =	6.60%			
CO2 MW =	44.01	lb/lb-mole		
CO2 Emissions =	42,209	lb/hr	179,875	TPY CO2
			18%	Contingency due to lack of performance guarantee
			212,999	TPY CO2

Coal Only Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,298	hr/yr
Half Rate	438	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	7.57	7.57	31.40
NOx	7.40	7.40	30.72
CO	13.63	13.63	56.54
H_2SO_4	3.64	3.64	15.09
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	3.78	3.78	0.83
NOx	3.70	3.70	0.81
CO	6.81	6.81	1.49
H_2SO_4	1.82	1.82	0.40
Mercury (HAP)	3.3E-10	3.3E-10	7.3E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	1.89	1.89	0.02
NOx	1.85	1.85	0.02
CO	3.41	3.41	0.04
H_2SO_4	0.91	0.91	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
SO_2	0.02	0.02	0.0006
NOx	3.85	3.85	0.12
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.006
Total VOC HAPs	0.06	0.06	0.0019
Mercury (HAP)	5.6E-05	5.6E-05	1.7E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO_2 = Annual CO_2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO_2 emission factor (kg CO_2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO_2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH_4
0.0001 N_2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH_4 = 0.0021 MT
N_2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	10393.9	lb-mole/hr		
CO2% =	10.262%			
CO2 MW =	44.01	lb/lb-mole		
CO2 Emissions =	46,941	lb/hr	200,039	TPY CO2
			18%	Contingency due to lack of performance guarantee
			236,877	TPY CO2

NAME Wet Sulfuric Acid (WSA) Unit Stack B

Unit ID: 015 B

Emissions of all pollutants are higher for the Coal / Coke Case.

STACK DATA

HEIGHT	200	ft
DIAMETER	4.83	ft
GAS EXIT TEMP	176	°F
GAS EXIT VELOCITY: Two Unit Operation	102.2	fps
GAS EXIT VELOCITY: One Unit Operation	51.1	fps
GAS EXIT VELOCITY: Black start	25.5	fps
GAS EXIT VELOCITY: Preheat	115.3	fps

COMBUSTION DATA

HEAT INPUT - Preheat	35.00	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
OPERATING HOURS: Two Unit Operation	8,298	hr/yr
OPERATING HOURS: One Unit Operation	438	hr/yr
OPERATING HOURS: Black-start	24	hr/yr
OPERATING HOURS: Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	34.44
NOx	10.17	10.17	42.20
CO	18.72	18.72	77.69
H_2SO_4	5.00	5.00	20.73
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.91
NOx	5.09	5.09	1.11
CO	9.36	9.36	2.05
H_2SO_4	2.50	2.50	0.55
Mercury (HAP)	3.3E-10	3.3E-10	7.3E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.0008
$PM_{2.5}$	0.02	0.02	0.0006
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

EMISSIONS: Normal Operations Total

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.00018	0.03	0.0008
$PM_{2.5}$	0.00015	0.02	0.0006
SO_2	8.08	8.30	35.37
NOx	9.92	10.17	43.46
CO	18.23	18.72	79.85
VOC	0.0013	0.19	0.006
Total VOC HAPs	0.0004	0.06	0.0019
Mercury (HAP)	4.0E-07	6.5E-02	1.8E-06
H_2SO_4	4.86	5.00	21.29
$PM_{2.5}$ including H_2SO_4	4.86	5.00	21.29

CALCULATIONS

Emissions Preheat Case: (PM10, VOC, and SO2)(Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)

Emissions Preheat Case: (NOx, CO) (Avg. lb/hr) = Vendor Factor (lb/MM Btu) X Heat Input (MMBtu/hr)

Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)

Average Emissions (lb/hr) = Maximum Emissions.

Preheat Case: Natural Gas Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

Source: Emission factors for NOx and CO are based on information from vendor supplied data.

Comments:

SO2 emissions for preheat case based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.

The emission rate data from the WSA Trains is based on information from process licensee.

Total WSA capacity for two trains is 136,658 lb/h of 97.5 wt% Sulfuric Acid production OR 1,599 stpd on dry basis (100% acid).

Burner flue gas is scrubbed in gasifier quench water to remove over 90% of particulate.

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Coal / Coke Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,298	hr/yr
Half Rate	438	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	8.30	8.30	34.44
NOx	10.17	10.17	42.20
CO	18.72	18.72	77.69
H_2SO_4	5.00	5.00	20.73
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	4.15	4.15	0.91
NOx	5.09	5.09	1.11
CO	9.36	9.36	2.05
H_2SO_4	2.50	2.50	0.55
Mercury (HAP)	3.3E-10	3.3E-10	7.1E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	2.08	2.08	0.02
NOx	2.54	2.54	0.03
CO	4.68	4.68	0.06
H_2SO_4	1.25	1.25	0.01
Mercury (HAP)	3.3E-10	3.3E-10	3.9E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.00078
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.9E-05	5.9E-05	1.8E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal-Coke)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1\times10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1\times10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per m 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	14538.1	lb-mole/hr		
CO2% =	6.60%			
CO2 MW =	44.01	lb/lb-mole		
CO2 Emissions =	42,209	lb/hr	179,875	TPY CO2
			18%	Contingency due to lack of performance guarantee
			212,999	TPY CO2

Coal Only Case

	35.00	MM Btu/hr
	1,020	Btu/ft^3
Full Rate	8,298	hr/yr
Half Rate	438	hr/yr
Black Start	24	hr/yr
Preheat	60	hr/yr

EMISSIONS: Full Rate

	lb/hr avg.	lb/hr max.	TPY
SO_2	7.57	7.57	31.40
NOx	7.40	7.40	30.72
CO	13.63	13.63	56.54
H_2SO_4	3.64	3.64	15.09
Mercury (HAP)	3.3E-10	3.3E-10	1.4E-09

EMISSIONS: Full Rate for 219 hr/yr OR Half Rate for 438 hr/yr

	lb/hr avg.	lb/hr max.	TPY
SO_2	3.78	3.78	0.83
NOx	3.70	3.70	0.81
CO	6.81	6.81	1.49
H_2SO_4	1.82	1.82	0.40
Mercury (HAP)	3.3E-10	3.3E-10	7.3E-11

EMISSIONS: Half Rate (including Black Start)

	lb/hr avg.	lb/hr max.	TPY
SO_2	1.89	1.89	0.02
NOx	1.85	1.85	0.02
CO	3.41	3.41	0.04
H_2SO_4	0.91	0.91	0.01
Mercury (HAP)	3.3E-10	3.3E-10	4.0E-12

EMISSIONS: Preheat

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.03	0.03	0.00078
SO_2	0.02	0.02	0.00062
NOx	3.85	3.85	0.116
CO	1.96	1.96	0.059
VOC	0.19	0.19	0.0057
Total VOC HAPs	0.06	0.06	0.00194
Mercury (HAP)	5.6E-05	5.6E-05	1.7E-06

Combustion	PM_{10}	VOC	SO_2
Factor (lb/MMscf)	7.600	5.50	0.60

Source: AP-42 (7/98), Section 1.4, Table 1.4-2 for VOC and PM10.

Preheat Case: Natural Gas Combustion	NOx	CO
Factor (lb/MMBtu)	0.110	0.056

	Natural Gas	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.61E-06

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Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID Billing Meter
Alt. Meter ID
Meter Name

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1×10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 111 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mr 0.001 CH4
0.0001 N2O

1×10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0021 MT
N2O = 0.0002 MT

Emission Points	Data Required	MRR Frequency	Data	Units
WSA Preheat Burners	Volume of the gaseous fuel combusted	Annual	2,058,824	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e
CO2	111	1	111
CH4	0.0	21	0
N2O	0.0	310	0
		TOTAL =	111

123 TPY CO2

Feeds to WSA (CO2 + combusted CO):

WSA Exhaust =	10393.9	lb-mole/hr
CO2% =	10.262%	
CO2 MW =	44.01	lb/lb-mole
CO2 Emissions =	46,941	lb/hr

200,039 TPY CO2
18% Contingency due to lack of performance guarantee
236,877 TPY CO2

COOLING TOWER

NAME ASU Cooling Water Tower CAP Unit ID:

Evaporative Cooler Operating Parameters				Emissions		Emis
Flow Rate, (gpm)	Drift Rate, %	Drift lb/hr	TDS (ppm)	PM lb/hr	PM TPY	PM2.5 lb/hr
54,956	0.0005	138	1,500	0.21	0.90	0.16

Comments:

The ASU Cooling Water Tower consists of 6 individual cells, which are being capped under EIQ No. 16a. The total water flow rate cannot exceed the CAP value, regardless of the number of cells in operation. Therefore, the emissions listed above are the capped total lb/hr and TPY.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Drift rate guaranteed by vendor.

Assume all dissolved solids to be PM_{10}. PM2.5 assumed to be 78% of total PM

Total Spray flow provided by B&V.

016a

ssions
PM2.5 TPY
0.70

COOLING TOWER

Page 2 of 2 TSD A

NAME Main Cooling Water Tower CAP Unit ID:

Evaporative Cooler Operating Parameters				Emissions		Emis
Flow Rate, (gpm)	Drift Rate, %	Drift lb/hr	TDS (ppm)	PM10 lb/hr	PM10 TPY	PM2.5 lb/hr
404,676	0.0005	1,013	1,500	1.52	6.65	1.18

Comments:

The Main Cooling Water Tower consists of 24 individual cells, which are being capped under EIQ No. 16b. The total water flow rate cannot exceed the CAP value, regardless of the number of cells in operation. Therefore, the emissions listed above are the capped total lb/hr and TPY.

PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Drift rate guaranteed by vendor.

Assume all dissolved solids to be $PM_{10.}$ PM2.5 assumed to be 78% of total PM

Total flow provided by B&V.

pp A

016b

ssions
PM2.5 TPY
5.19

NAME ASU Molecular Sieve Regeneration Vents

The molecular sieves are regenerated by blowing nitrogen through them.

STACK DATA

HEIGHT	60	ft
DIAMETER	8	ft
GAS EXIT TEMP	260	°F
GAS EXIT VELOCITY	62.02	fps
OPERATING HOURS (each)	1,752	hr/yr

PM_{10} EMISSIONS	Average Emissions	Maximum Hourly	Annual PM_{10} Emissions	Annual $PM_{2.5}$ Emissions
Unit ID	lb/hr	lb/hr	TPY	TPY
017 A	0.13	0.13	0.11	0.039
017 B	0.13	0.13	0.11	0.039
Total	0.25	0.25	0.22	0.077

Regeneration occurs for 1 hr out of every 5 hr for each molecular sieve.
The vent stream is primarily nitrogen (>98%), with a trace amount of particulates.
Emissions based on engineered equipment data
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM10] (Calc for each pile)

TYPES OF TRUCKS	**AVERAGE* TRUCK WEIGHT TONS**	**UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT**	**UNPAVED PRECIPITATION CORRECTION**	**UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT**	**Trucks Trips per day**	**Trucks Trips per hour**
COAL PILE DOZER OPERATIONS	41.38	1.061	0.68	0.73	155	12.9

ASSUMPTIONS		
CAT 824H Wheel Dozer	**lbs**	**Tons**
Estimate Total Capacity	**100,195**	**50.10**
Tare	**65,325**	**32.66**
Estimate Capacity	**34,870**	**17.44**
Average Equipment Weight	**82,760**	**41.38**
Maximum Feedstock moved each hr (12hr/day)	**450,000**	**225.00**
Maximum Number of Trips per Hour	**12.9**	

Unpaved Road Equation is based on speeds of 15-45 mph.
Based on the speed of the dozer - 3 - 8 mph, an overall 95% control efficiency is possible.
Wet suppression is used for additional control.

A 90% control efficiency is being conservatively used.

Average daily dozer travel distance each trip assumed to be 1/2 pile radius times two (for round trip).

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM10] (Calc. for each pile)

MILES ROUND TRIP PAVED	MILES ROUND TRIP UNPAVED each trip	ON-SITE VMT/DAY UNPAVED	UNCONTROLLED EMISSIONS LBS/DAY	PERCENT CONTROL	CONTROLLED EMISSIONS LBS/DAY	Ave Daily CONTROLLED EMISSIONS LBS/HR*	CONTROLLED EMISSIONS Tons/yr
0	0.05105	7.91	5.7	90%	0.5747	0.0239	0.1049

UNPAVED ROADS EQUATIONS

$$E = k * \left(s / 12 \right)^{a} * \left(W / 3 \right)^{b}$$

$$E_{ext} = E \left(\frac{365 - P}{365} \right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Coal Trucks = 50 tons, Ash Trucks = 50 tons, Limestone Trucks = 25 tons

Eext = natural mitigation emission factor (lb/VMT)
P = number of days per year with 0.01 in or more of precipitation

INPUTS

k	1.5	lb/VMT	
s	2.2	%	AP-42 13.2.4-1
a	0.9		
b	0.45		
P	115	days	

P	115	wet days/yr

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM2.5] (each pile)

TYPES OF TRUCKS	AVERAGE* TRUCK WEIGHT TONS	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	UNPAVED PRECIPITATION CORRECTION	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	Trucks Trips per day	Trucks Trips per hour
COAL PILE DOZER OPERATIONS	41.38	0.106	0.68	0.07	155	12.9

ASSUMPTIONS

CAT 824H Wheel Dozer	**lbs**	**Tons**
Estimate Total Capacity	**100,195**	**50.10**
Tare	**65,325**	**32.66**
Estimate Capacity	**34,870**	**17.44**
Average Equipment Weight	**82,760**	**41.38**
Maximum Feedstock moved each hr (12hr/day)	**450,000**	**225.0**
Maximum Number of Trips per Hour	**12.9**	

Unpaved Road Equation is based on speeds of 15-45 mph.
Based on the speed of the dozer - 3 - 8 mph, an overall 95% control efficiency is reasonable.

Average daily dozer travel distance each trip assumed to be 1/2 pile radius times two (for round trip).

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / PM2.5] (each pile)

MILES ROUND TRIP PAVED	MILES ROUND TRIP UNPAVED* each trip		ON-SITE VMT/DAY UNPAVED		UNCONTROLLED EMISSIONS LBS/DAY		PERCENT CONTROL	CONTROLLED EMISSIONS LBS/DAY	Ave Daily CONTROLLED EMISSIONS LBS/HR*	CONTROLLED EMISSIONS Tons/yr
0	0.05105		7.9		0.57		90%	0.0575	0.0024	0.0105

UNPAVED ROADS EQUATIONS

$$E = k * \left(s/12\right)^{a} * \left(W/3\right)^{b}$$

$$E_{ext} = E\left(\frac{365 - P}{365}\right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Coal Trucks = 50 tons, Ash Trucks = 50 tons, Limestone Trucks = 25 tons

Eext = natural mitigation emission factor (lb/VMT)
P = number of days per year with 0.01 in or more of precipitation

INPUTS

k 0.15 lb/VMT
s 2.2 % AP-42 13.2.4-1
a 0.9
b 0.45
P 115 days

P 115 wet days/yr

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / Total Particulate]

TYPES OF TRUCKS	AVERAGE* TRUCK WEIGHT TONS	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	UNPAVED PRECIPITATION CORRECTION	UNCONTROLLED EMISSION FACTOR UNPAVED lb/VMT	Trucks Trips per day	Trucks Trips per hour
COAL PILE DOZER OPERATIONS	41.38	4.868	0.68	3.33	155	12.9

ASSUMPTIONS		
CAT 824H Wheel Dozer	**lbs**	**Tons**
Estimate Total Capacity	**100,195**	**50.10**
Tare	**65,325**	**32.66**
Estimate Capacity	**34,870**	**17.44**
Average Equipment Weight	**82,760**	**41.38**
Maximum Feedstock moved each hr (12hr/day)	**450,000**	**225.00**
Maximum Number of Trips per Hour	**12.9**	

Unpaved Road Equation is based on speeds of 15-45 mph.
Based on the speed of the dozer - 3 - 8 mph, an overall 95% control efficiency is possible.
Wet suppression is used for additional control.

A 90% control efficiency is being conservatively used.

Average daily dozer travel distance each trip assumed to be 1/2 pile radius times two (for round trip).

Emission Calculation for Dozer Activity on the pile [EU-012P & EU-012Q / Total Particulate]

MILES ROUND TRIP PAVED	**MILES ROUND TRIP UNPAVED each trip**		**ON-SITE VMT/DAY UNPAVED**		**UNCONTROLLED EMISSIONS LBS/DAY**		**PERCENT CONTROL**	**CONTROLLED EMISSIONS LBS/DAY**	Ave Daily **CONTROLLED EMISSIONS LBS/HR***
0	0.05105		7.91		26.4		90%	2.6357	0.1098

UNPAVED ROADS EQUATIONS

$$E = k * \left(s/_{12} \right)^{a} * \left(W/_{3} \right)^{b}$$

$$E_{ext} = E \left(\frac{365 - P}{365} \right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Vehicle average weight

Eext = natural mitigation emission factor (lb/VMT)
P = number of days per year with 0.01 in or more of precipitation

INPUTS

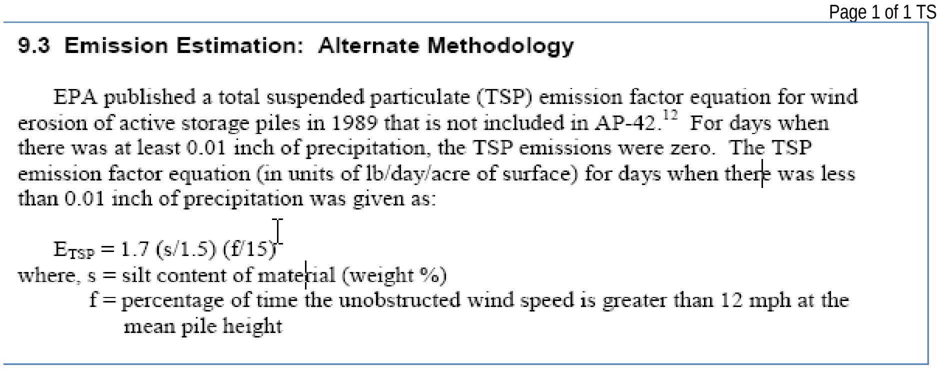
k	4.9	lb/VMT	
s	2.2	%	AP-42 13.2.4-1
a	0.7		
b	0.45		
P	115	days	

P	115	wet days/yr

CONTROLLED EMISSIONS Tons/yr
0.4810

Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

Basis: Wrap Fugitive Dust Handbook, Prepared for Governers Conference, Western Regional Air Partnership (WRAP) Methodology for wind erosion.



9.3 Emission Estimation: Alternate Methodology

EPA published a total suspended particulate (TSP) emission factor equation for wind erosion of active storage piles in 1989 that is not included in AP-42.[12] For days when there was at least 0.01 inch of precipitation, the TSP emissions were zero. The TSP emission factor equation (in units of lb/day/acre of surface) for days when there was less than 0.01 inch of precipitation was given as:

$$E_{TSP} = 1.7\ (s/1.5)\ (f/15)$$

where, s = silt content of material (weight %)
f = percentage of time the unobstructed wind speed is greater than 12 mph at the mean pile height

Referened document can be obtained at:
http://www.wrapair.org/forums/dejf/fdh/content/Ch9-Storage_Pile_Wind%20Erosion_Rev06.pdf

WRAP document basis for equation is stated to be from 1989 EPA document:
USEPA, January 1989. Air/Superfund National Technical Guidance Study Series; Volume III – Estimation of Air Emissions from Cleanup Activities at Superfund Sites, Interim final report EPA-450/1-89-003.

Assumptions

	Data	Descript.	Basis
silt	2.20	% (s) Silt content	AP-42 13.2.4-1, Coal as received, coal power plant. Also used for coke (coke should be lower).
% windy	100.00	% (f) % high wind	Conservatively assume high winds on worse case day.
PM10 Multiplier	0.5	ratio PM10 vs TSP	
PM2.5 Multiplier	0.053	ratio PM2.5 vs TSP	
Control effective.	90%	Watering and compaction / BACT	
Pile size coal	6.230	acres (see attached Surf. Area Calcs.)	
Pile size coke	5.180	acres (see attached Surf. Area Calcs.)	

Calculated Emiss. Factors from above Equation

Uncontrolled Emissions Factors

TSP	16.62	lb/day/acre of surface
PM10	8.31	lb/day/acre of surface
PM2.5	0.881	lb/day/acre of surface

Controlled Emissions Factors

PM10	0.83	lb/day/acre of surface
PM2.5	0.088	lb/day/acre of surface

Calculated Emissions Rate

Controlled Emissions Rate - lb/hr worse case day
*(= Controlled factor * acres / 24hr/day)*

Coal Pile			***Coke Pile***		
PM10	**0.216**	**lb PM10/hr**	**PM10**	**0.179**	**lb PM10/hr**
PM2.5	**0.023**	**lb PM2.5/hr**	**PM2.5**	**0.019**	**lb PM2.5/hr**

Annual Emissons - conservatively assuming max rate on all days.

PM10	**0.94**	**TPY PM10**	**PM10**	**0.79**	**TPY PM10**
PM2.5	**0.10**	**TPY PM2.5**	**PM2.5**	**0.08**	**TPY PM2.5**

Note: the above method is used for calculating emissions for air modeling purposes in preference to AP42 section 13.2.5 because, as stated in AP42 section 13.2.5, page 13.2.5-3, regarding its wind erosion formula:
". . .Calculated emissions represent intermittent events and should not be input directly into dispersion models that assume steady-state emission rates. "

Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

6.23 acres

coal pile surface area = 271,379 ft^2

top height = 203

top diameter = 150

top slant = 135.62 √[(top height - pile height)^2+(top diameter/2)^2]

pile height = 90

pile diameter = 539

pile slant = 337.40 √[(top height)^2+(pile diameter/2)^2]

Surface area truncated cone = SA of whole cone - SA of top/removed cone + area of top.

$$\boxed{SA = \pi * r_p * s_p - \pi * r_t * s_t + \pi * r_t^2}$$

5.18 acres

coke pile surface area = 225,647 ft^2

top height = 186

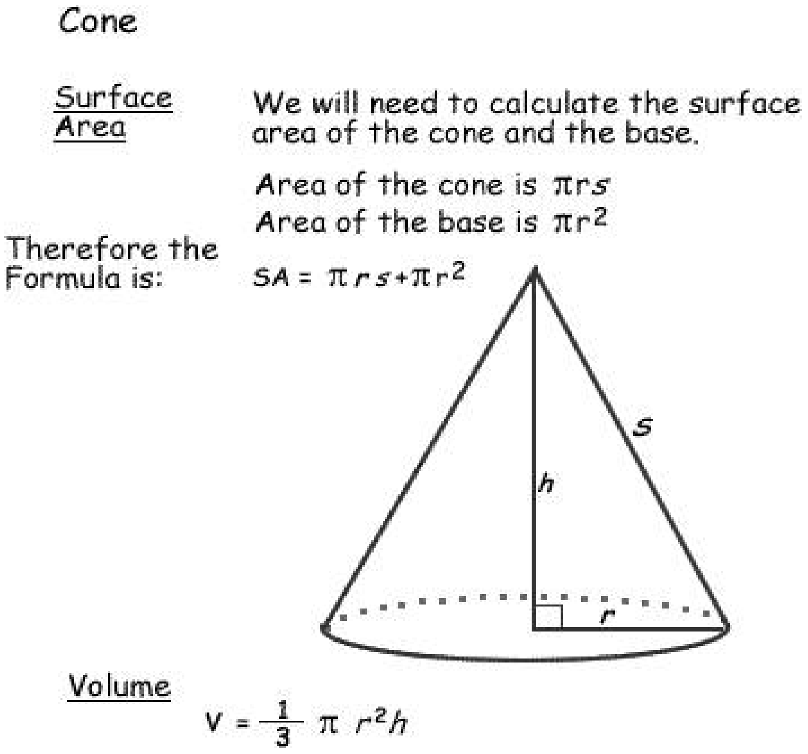
top diameter = 150

top slant = 135.62 √[(top height - pile height)^2+(top diameter/2)^2]

pile height = 73

pile diameter = 494

pile slant = 309.20 √[(top height)^2+(pile diameter/2)^2]



Cone

Surface Area

We will need to calculate the surface area of the cone and the base.

Area of the cone is $\pi r s$

Area of the base is πr^2

Therefore the Formula is:

$SA = \pi r s + \pi r^2$

Volume

$V = \frac{1}{3} \pi r^2 h$

AGRICO STACKER STORAGE PILE CAPACITY

Emissions Calculations for Fugitive Dust from Wind Erosion [EU-012W &EU-012X]

	Coke x 1	100% coal	85% coal	51% coal	
BOOM REACH	**135.00**	**150.00**	**150.00**	**150.00**	FT
ANGLE OF REPOSE	**37.00**	**37.00**	**37.00**	**37.00**	DEGREES
PILE HEIGHT	**73.00**	**90.00**	**90.00**	**90.00**	FT
TOWER RADIUS	**20.00**	**20.00**	**20.00**	**20.00**	FT
TANGENT	0.75	0.75	0.75	0.75	
OUTSIDE CONE RADIUS	231.87	269.43	269.43	269.43	FT
OUTSIDE PILE DIAMETER	463.74	538.85	538.85	538.85	FT
PI*R*R	168,901.00	228,051.00	228,051.00	228,051.00	SQ FT
HEIGHT OF TOTAL CONE	174.74	203.04	203.04	203.04	FT
TOTAL CONE CAPACITY	9,837,695.00	15,434,491.70	15,434,491.70	15,434,491.70	CU FT
TOP CONE RADIUS	135.00	150.00	150.00	150.00	FT
PI*R*R	57,255.50	70,685.80	70,685.80	70,685.80	
HEIGHT OF TOP CONE	101.74	113.04	113.04	113.04	FT
TOP CONE CAPACITY	1,941,649.00	2,663,441.00	2,663,441.00	2,663,441.00	CU FT
INSIDE TOWER	1,257.00	1,257.00	1,257.00	1,257.00	SQ FT
LOSS CAPACITY - TOWER	91,761.00	113,130.00	113,130.00	113,130.00	CU FT
NET CAPACITY	7,804,285.00	12,657,920.70	12,657,920.70	12,657,920.70	CU FT
MAT'L DENSITY	**47.00**	**50.00**	**50.00**	**50.00**	LB/CU FT
NET CAPACITY	366,801,395.00	632,896,035.00	632,896,035.00	632,896,035.00	LBS
	2,000.00	2,000.00	2,000.00	2,000.00	LBS/TON
NET CAPACITY	183,400.70	316,448.00	316,448.00	316,448.00	TONS
AREA OF PILE	168,901.25	228,050.64	228,050.64	228,050.64	SQ FT
AREA OF PILE	3.88	5.24	5.24	5.24	ACRES
DAYS STORAGE	44.87	33.08	38.92	64.86	DAYS each
Coal Consumption (100% fuel)		9,565.00	8,131.10	4,878.66	tpd
Coke Consumption (49% fuel)	4,087.00				tpd

	%	Tons	Days storage
Coke	49%	4,087.00	44.87
Coal	51%	4,878.15	64.87
	85%	8,130.25	38.92
	100%	9,565.00	33.08

NAME ZLD Spray Dryer Stack Unit ID: 032

STACK DATA

HEIGHT	100	ft
DIAMETER	1	ft
GAS EXIT TEMP	310	°F
GAS EXIT VELOCITY	35.49	fps

COMBUSTION DATA

HEAT INPUT	5.6	MM Btu/hr
AP-42 NATURAL GAS HEAT VALUE	1,020	Btu/ft^3
PROCESS FLOW RATE	2,735	dscfm
OPERATING HOURS	8,760	hr/yr

EMISSIONS:

	lb/hr avg.	lb/hr max.	TPY
PM_{10}	0.12	0.12	0.51
$PM_{2.5}$	0.11	0.11	0.48
SO_2	0.003	0.003	0.015
NOx	0.197	0.197	0.86
CO	0.203	0.203	0.89
VOC	0.030	0.030	0.13
Total VOC HAPs	0.010	0.010	0.046
Mercury (HAP)	9.4E-06	9.4E-06	4.1E-05

CALCULATIONS

Emissions (SO2) (Avg. lb/hr) = AP-42 Factor (lb/MMscf)/ AP-42 Natural Gas Heat Value (Btu/ft^3) X Heat Input (MMBtu/hr)
Emissions (NOx, CO, VOC) (Avg. lb/hr) = Vendor Factor (lb/MM Btu/hr) x Heat Input (MMBtu/hr)

Emissions (TPY) = Emissions (lb/hr) x (Operating hr/yr / 2000 lb/ton)
Average Emissions (lb/hr) = Maximum Emissions.

Natural Gas Combustion	SO_2
Factor (lb/MM scf)	0.60

Fabric Filter	PM_{10}
Factor (gr/dscf)	0.0050

Natural Gas Combustion	NOx	CO	VOC
Factor (lb/MM Btu)	0.035	0.036	0.005

Source: Emission factors for NOx, CO, VOC and PM10 are based on information from vendor supplied data.

	Natural Gas	SNG (Coal-Coke)	SNG (Coal Only)
Mercury Factor (lb/MMBtu)	1.95E-07	1.68E-06	1.61E-06

Comments:

SO2 emissions based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content in natural gas of 2,000 grains/10^6 scf (<5 ppmv of H2S).
Natural gas or SNG may be combusted. Conservatively assumed natural gas for SO2 calculation (as SNG contains no sulfur).
Total HAPs are based on AP-42 Section 1.4, Tables 1.4-3 and 1.4-4.
PM2.5 emissions ratioed from PM10 emissions. Ratios are from EPAs PM calculator for SCCs per Roy Huntley (EPA EI and Analysis Group).

Stationary Combustion Sources - Natural Gas (semi-annual or more frequent analysis)

Meter ID	Billing Meter
Alt. Meter ID	
Meter Name	

$$CO_2 = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-2a

CO2 = Annual CO2 mass emissions (metric tons)
Fuel = Annual volume of the gaseous fuel combusted (scf)
HHV = Annual average high heat value (MMBtu per mass or volume)
EF = Fuel-specific default CO2 emission factor (kg CO2/MMBtu) = 53.02
1 x 10^{-3} = Conversion factor from kilograms to metric tons

CO2 = 2,616 MT

$$CH_4 or N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF$$

Equation C-9a

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons)
Fuel = Mass or volume of the fuel combusted during the reporting year
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (MMBtu per mass or volume)
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 = (kg CH_4 or N_2O per mmBtu) = 0.001 CH4
0.0001 N2O

1 x 10^{-3} = Conversion factor from kilograms to metric tons

CH4 = 0.0493 MT
N2O = 0.0049 MT

Emission Points	Data Required	MRR Frequency	Data	Units
ZLD Spray Dryer Stack	Volume of the gaseous fuel combusted	Annual	48,379,046	scf
	High heat value of the fuel from all valid samples for the year	Annual Average	0.00102	MMBtu per scf

GHG Pollutant	GHG Metric Tons	GWP Factors	Metric Tons CO2e		
CO2	2,616	1	2,616		
CH4	0.049	21	1		
N2O	0.0049	310	2		
		TOTAL =	2,619	2,886	TPY CO2

VENT SOURCES

NAME ZLD Inert Gas Vent Unit ID: 033

Mercury is controlled using a sulfided carbon adsorbent with a vendor guarantee of 0.5 ppbv.

STACK DATA

HEIGHT	15	ft
DIAMETER	0.083	ft
GAS EXIT TEMP	150	°F
GAS EXIT VELOCITY	31.74	fps
OPERATING HOURS	8,760	hr/yr

EMISSIONS	Average Emissions lb/hr	Maximum Hourly lb/hr	Average Annual Emissions lb/yr	Average Annual Emissions TPY
Carbon Dioxide	46.50	46.50	407,340	203.7
Mercury	1.40E-07	0.0149	0.7168	< 0.001

Assumptions:

Vent stream is 75.5% CO2 and 24.5% H20.

Mercury in solids feed to Gasifier at max is 0.745 lb/hr

Gasification process wastewater picks up 2% of the mercury in the gasifiers, resulting in 0.0149 lb/hr mercury in the water, all of which goes to the ZLD inert gas vent.

Sulfided carbon adsorbent control is >99.99% effective, but is offline up to 2 days/year for carbon changeout.

Basis of Total HAP Emission Factor for Natural Gas Combustion

Project: Indiana Gasification

Emissions Estimation

AP-42 Heating Value 1,020 Btu/scf

EMISSION FACTOR BASED INVENTORY		**AP-42 Em. Factor**			**Notes**
POLLUTANT	**CAS #**	**Em.Fac. Source**	**lb/MMscf**	**lb/MMBtu**	
2-Methylnaphthalene	91-57-6	AP-42, Table 1.4-3	2.40E-05	2.35E-08	b
3-Methylchloranthrene	56-49-5	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b
7,12-Dimethylbenz(a)anthracene	---	AP-42, Table 1.4-3	1.60E-05	1.57E-08	b, c
Acenaphthene	83-32-9	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Acenaphthylene	203-96-8	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Anthracene	120-12-7	AP-42, Table 1.4-3	2.40E-06	2.35E-09	b, c
Benz(a)anthracene	56-55-3	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Benzene	71-43-2	AP-42, Table 1.4-3	2.10E-03	2.06E-06	b
Benzo(a)pyrene	50-32-8	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Benzo(b)fluoranthene	205-99-2	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Benzo(g,h,i)perylene	191-24-2	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Benzo(k)fluoranthene	205-82-3	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Chrysene	218-01-9	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Dibenzo(a,h)anthracene	53-70-3	AP-42, Table 1.4-3	1.20E-06	1.18E-09	b, c
Dichlorobenzene	25321-22-6	AP-42, Table 1.4-3	1.20E-03	1.18E-06	b
Fluoranthene	206-44-0	AP-42, Table 1.4-3	3.00E-06	2.94E-09	b, c
Fluorene	86-73-7	AP-42, Table 1.4-3	2.80E-06	2.75E-09	b, c
Formaldehyde	50-00-0	AP-42, Table 1.4-3	7.50E-02	7.35E-05	b
Hexane	110-54-3	AP-42, Table 1.4-3	1.80E+00	1.76E-03	b
Indeno(1,2,3-cd)pyrene	193-39-5	AP-42, Table 1.4-3	1.80E-06	1.76E-09	b, c
Naphthalene	91-20-3	AP-42, Table 1.4-3	6.10E-04	5.98E-07	b
Phenanathrene	85-01-8	AP-42, Table 1.4-3	1.70E-05	1.67E-08	b, c
Pyrene	129-00-0	AP-42, Table 1.4-3	5.00E-06	4.90E-09	b, c
Toluene	108-88-3	AP-42, Table 1.4-3	3.40E-03	3.33E-06	b
Arsenic	7440-38-2	AP-42, Table 1.4-4	2.00E-04	1.96E-07	b
Beryllium	7440-41-7	AP-42, Table 1.4-4	1.20E-05	1.18E-08	b
Cadmium	7440-43-9	AP-42, Table 1.4-4	1.10E-03	1.08E-06	b
Chromium	7440-47-3	AP-42, Table 1.4-4	1.40E-03	1.37E-06	b
Cobalt	7440-48-4	AP-42, Table 1.4-4	8.40E-05	8.24E-08	b
Manganese	7439-96-5	AP-42, Table 1.4-4	3.80E-04	3.73E-07	b
Mercury	7439-97-6	AP-42, Table 1.4-4	2.60E-04	2.55E-07	b
Nickel	7440-02-0	AP-42, Table 1.4-4	2.10E-03	2.06E-06	b
Selenium	7782-49-2	AP-42, Table 1.4-4	2.40E-05	2.35E-08	b
		Total HAP =	1.88796	0.00185	

Notes:

a. Criteria pollutant by name or association, i.e., VOC as surrogates for O3
b. Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.
c. HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of Clean Air Act
d. non-VOC per 40 CFR 51.100(s)(1); methane and ethane are not considered as regulated photochemical reactive VOC
e. Soot in concentration values, 0 micrograms per liter (ug/L); lightly smoking flares, 40 ug/L; average smoking flares, 177 ug/L; and heavily smoking flares 274 ug/L.
f. To be used where source testing or fuel analysis are not required by the AB2588 Criteria and Guidelines Regulations, Appendix D
g. Based on 100% conversion of fuel sulfur to SO2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

		lb/hr (per individual emission unit, maximum short term)												
EMISSION FACTOR BASED INVENTORY		**001**	**002**	**005**	**007**	**008**	**015**	**024**	**025**	**029**	**030**	**032**	**FUG**	
Number of emission units		1	1	2	2	5	2	1	1	1	1	1	1	**Notes**
POLLUTANT	**CAS #**	**0.27**	**0.27**	**408.17**	**38.81**	**35.00**	**35.00**	**-**	**-**	**-**	**-**	**5.63**	**-**	**MMBtu/hr**
2-Methylnaphthalene	91-57-6	6.24E-09	6.24E-09	9.60E-06	9.13E-07	4.12E-06	8.24E-07	-	-	-	-	1.33E-07	-	b
3-Methylchloranthrene	56-49-5	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b
7,12-Dimethylbenz(a)anthracene	---	4.16E-09	4.16E-09	6.40E-06	6.09E-07	2.75E-06	5.49E-07	-	-	-	-	8.84E-08	-	b, c
Acenaphthene	83-32-9	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Acenaphthylene	203-96-8	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Anthracene	120-12-7	6.24E-10	6.24E-10	9.60E-07	9.13E-08	4.12E-07	8.24E-08	-	-	2.88E-07	-	1.33E-08	-	b, c
Arsenic	7440-38-2	5.20E-08	5.20E-08	8.00E-05	7.61E-06	3.43E-05	6.86E-06	-	-	-	-	1.10E-06	-	b
Benz(a)anthracene	56-55-3	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Benzene	71-43-2	5.46E-07	5.46E-07	8.40E-04	7.99E-05	3.60E-04	7.21E-05	-	-	1.08E-03	5.59E-05	1.16E-05	-	b
Benzo(a)pyrene	50-32-8	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Benzo(b)fluoranthene	205-99-2	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Benzo(g,h,i)perylene	191-24-2	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Benzo(k)fluoranthene	205-82-3	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Beryllium	7440-41-7	3.12E-09	3.12E-09	4.80E-06	4.57E-07	2.06E-06	4.12E-07	-	-	-	-	6.63E-08	-	b
Biphenyl	92-52-4	-	-	-	-	-	-	-	-	3.18E-06	-	-	-	b,c
Cadmium	7440-43-9	2.86E-07	2.86E-07	4.40E-04	4.19E-05	1.89E-04	3.77E-05	-	-	-	-	6.07E-06	-	b
Carbonyl Sulfide	463-58-1	6.67E-02	-	-	7.80E-02	-	-	-	-	-	-	-	2.82E-03	b
Chromium	7440-47-3	3.64E-07	3.64E-07	5.60E-04	5.33E-05	2.40E-04	4.80E-05	-	-	-	-	7.73E-06	-	b
Chrysene	218-01-9	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Cobalt	7440-48-4	2.18E-08	2.18E-08	3.36E-05	3.20E-06	1.44E-05	2.88E-06	-	-	-	-	4.64E-07	-	b
Cumene	98-82-8	-	-	-	-	-	-	-	-	-	4.65E-06	-	-	b
Dibenzo(a,h)anthracene	53-70-3	3.12E-10	3.12E-10	4.80E-07	4.57E-08	2.06E-07	4.12E-08	-	-	-	-	6.63E-09	-	b, c
Dichlorobenzene	25321-22-6	3.12E-07	3.12E-07	4.80E-04	4.57E-05	2.06E-04	4.12E-05	-	-	-	-	6.63E-06	-	b
Ethylbenzne	100-41-4	-	-	-	-	-	-	-	-	5.37E-03	2.07E-05	-	-	b
Fluoranthene	206-44-0	7.80E-10	7.80E-10	1.20E-06	1.14E-07	5.15E-07	1.03E-07	-	-	-	-	1.66E-08	-	b, c
Fluorene	86-73-7	7.28E-10	7.28E-10	1.12E-06	1.07E-07	4.80E-07	9.61E-08	-	-	-	-	1.55E-08	-	b, c
Formaldehyde	50-00-0	1.95E-05	1.95E-05	3.00E-02	2.85E-03	1.29E-02	2.57E-03	-	-	-	-	4.14E-04	-	b
Hexane	110-54-3	4.68E-04	4.68E-04	7.20E-01	6.85E-02	3.09E-01	6.18E-02	-	-	-	5.42E-04	9.94E-03	-	b
Indeno(1,2,3-cd)pyrene	193-39-5	4.68E-10	4.68E-10	7.20E-07	6.85E-08	3.09E-07	6.18E-08	-	-	-	-	9.94E-09	-	b, c
Manganese	7439-96-5	9.88E-08	9.88E-08	1.52E-04	1.45E-05	6.52E-05	1.30E-05	-	-	-	-	2.10E-06	-	b
Mercury	7439-97-6	6.76E-08	6.76E-08	1.04E-04	9.89E-06	4.46E-05	8.92E-06	-	-	-	-	1.44E-06	-	b
Methanol	67-56-1	-	-	-	1.56E+00	-	-	3.58E-02	3.03E-02	-	-	-	8.40E-02	b
Naphthalene	91-20-3	1.59E-07	1.59E-07	2.44E-04	2.32E-05	1.05E-04	2.09E-05	-	-	2.05E-04	-	3.37E-06	-	b
Nickel	7440-02-0	5.46E-07	5.46E-07	8.40E-04	7.99E-05	3.60E-04	7.21E-05	-	-	-	-	1.16E-05	-	b
Phenanathrene	85-01-8	4.42E-09	4.42E-09	6.80E-06	6.47E-07	2.92E-06	5.83E-07	-	-	-	-	9.39E-08	-	b, c
Pyrene	129-00-0	1.30E-09	1.30E-09	2.00E-06	1.90E-07	8.58E-07	1.72E-07	-	-	-	-	2.76E-08	-	b, c
Selenium	7782-49-2	6.24E-09	6.24E-09	9.60E-06	9.13E-07	4.12E-06	8.24E-07	-	-	-	-	1.33E-07	-	b
Toluene	108-88-3	8.84E-07	8.84E-07	1.36E-03	1.29E-04	5.83E-04	1.17E-04	-	-	3.21E-03	1.40E-04	1.88E-05	-	b
Xylene	1330-20-7	-	-	-	-	-	-	-	-	6.85E-03	4.26E-05	-	-	b
Total		6.72E-02	4.91E-04	7.55E-01	1.71E+00	3.24E-01	6.48E-02	3.58E-02	3.03E-02	1.67E-02	8.05E-04	1.04E-02	8.69E-02	-

Notes:
a. Criteria pollutant by name or association, i.e., VOC as surrogates for O3
b. Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.
c. HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of Clean Air Act
d. non-VOC per 40 CFR 51.100(s)(1); methane and ethane are not considered as regulated photochemical reactive VOC
e. Soot in concentration values, 0 micrograms per liter (ug/L); lightly smoking flares, 40 ug/L; average smoking flares, 177 ug/L; and heavily smoking flares 274 ug/L.
f. To be used where source testing or fuel analysis are not required by the AB2588 Criteria and Guidelines Regulations, Appendix D
g. Based on 100% conversion of fuel sulfur to SO2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO2 emission factor in this table can
be converted to other natural gas sulfur contents by multiplying the SO2 emission factor by the ratio of
the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

h. lb/hr Values in columns 024, 025, 029, and 030 are sourced from the Tanks Emissions Calculations
i. lb/hr Vlaues in column FUG are sourced from the Fugitive Emissions Calculations
j. the lb/hr vlaues for Methanol and Carbonyl Sulfide in Unit 007 are sourced from the Combustion Emissions Calculations
k. Thelb/hr value fro Carbonyl Sulfide in Unit 001 is sourced from the Flares Emissions Calculations

NAME Fugitive Emissions - Gasification, Shift Conversion, Methanation, AGR (Rectisol) Unit ID: FUG

Methanol fugitives in the AGR (Rectisol) Unit: 100% Methanol

Fugitive Source	Stream Type	Component Count	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
			lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Gas	0	0.0089	0	97	0	0
	Light Liquid	250	0.0035	0.875	97	0.026	0.11
	Heavy Liquid	0	0.0007	0	0	0	0
Flanges	Gas	0	0.0029	0	30	0	0
	Light Liquid	500	0.0005	0.250	97	0.008	0.033
	Heavy Liquid	0	0.00007	0	30	0	0
Pumps	Light Liquid	8	0.0386	0.309	85	0.046	0.20
	Heavy Liquid	0	0.0161	0	0	0	0
Compressors	Gas	0	0.5027	0	75	0	0
Relief Valves	Gas	0	0.2293	0	100	0	0
	Light Liquid	19	0.0035	0.067	100	0	0
Sampling Connections	All	4	0.033	0.132	97	0.004	0.017
Total Methanol		781				0.08	0.37

VOC fugitives in the AGR (Rectisol) Unit: 100% non-TAP VOC (propylene)

Fugitive Source	Stream Type	Component Count	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
			lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Gas	78	0.0089	0.694	97	0.021	0.09
	Light Liquid	33	0.0035	0.116	97	0.003	0.015
	Heavy Liquid	0	0.0007	0	0	0	0
Flanges	Gas	193	0.0029	0.560	97	0.017	0.074
	Light Liquid	82	0.0005	0.041	97	0.001	0.005
	Heavy Liquid	0	0.00007	0	30	0	0
Pumps	Light Liquid	2	0.0386	0.077	85	0.012	0.051
	Heavy Liquid	0	0.0161	0	0	0	0
Compressors	Gas	3	0.5027	1.508	85	0.23	0.99
Relief Valves	Gas	7	0.2293	1.605	100	0	0
	Light Liquid	0	0.0035	0	100	0	0
Sampling Connections	All	1	0.033	0.033	97	0.001	0.004
Total VOCs		399				0.28	1.23

Carbonyl Sulfide

Fugitive Source	Process Stream	Component Count	COS Conc %v	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
				lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	0.029	0.0089	0.00026	0	2.6E-04	1.1E-03
	Shifted Syngas	50	0.008	0.0089	0.00003	0	3.3E-05	1.5E-04
	Mixed Syngas	100	0.024	0.0089	0.00022	0	2.2E-04	0.00095
	Sweet Syngas	20	5.0E-07	0.0089	8.9E-10	0	8.9E-10	3.9E-09
Flanges	Raw Syngas	250	0.029	0.0029	0.00021	0	2.1E-04	0.00093
	Shifted Syngas	100	0.008	0.0029	0.00002	0	2.2E-05	9.5E-05
	Mixed Syngas	250	0.024	0.0029	0.00018	0	1.8E-04	0.00077
	Sweet Syngas	50	5.0E-07	0.0029	7.3E-10	0	7.3E-10	3.2E-09
Compressor Seals	Raw Syngas	0	0.029	0.5027	0	0	0	0
	Shifted Syngas	0	0.008	0.5027	0	0	0	0
	Mixed Syngas	0	0.024	0.5027	0	0	0	0
	Sweet Syngas	0	5.0E-07	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.029	0.0386	0	0	0	0
	Shifted Syngas	0	0.008	0.0386	0	0	0	0
	Mixed Syngas	0	0.024	0.0386	0	0	0	0
	Sweet Syngas	0	5.0E-07	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.029	0.2293	0.00134	0	0.0013	0.0059
	Shifted Syngas	4	0.008	0.2293	0.00007	0	6.9E-05	3.0E-04
	Mixed Syngas	8	0.024	0.2293	0.00045	0	4.5E-04	0.00196
	Sweet Syngas	4	5.0E-07	0.2293	4.6E-09	0	4.6E-09	2.01E-08
Sample Connections	Raw Syngas	2	0.029	0.033	0.00002	0	1.9E-05	8.5E-05
	Shifted Syngas	2	0.008	0.033	0.00000	0	5.0E-06	2.2E-05
	Mixed Syngas	2	0.024	0.033	0.00002	0	1.6E-05	7.0E-05
	Sweet Syngas	2	5.0E-07	0.033	3.3E-10	0	3.3E-10	1.4E-09
Total COS							2.8E-03	1.2E-02

No Control Efficiency claimed due to low concentration.

Total VOCs = 0.37 1.61

Carbon Monoxide

Fugitive Source	Process Stream	Component Count	CO Conc %v	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
				lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	20.4	0.0089	0.18156	0	0.1816	0.795
	Shifted Syngas	50	3.7	0.0089	0.01666	0	1.7E-02	0.073
	Mixed Syngas	100	14.8	0.0089	0.13181	0	0.1318	0.577
	Sweet Syngas	20	22.5	0.0089	0.03997	0	0.0400	0.175
Flanges	Raw Syngas	250	20.4	0.0029	0.14790	0	0.1479	0.648
	Shifted Syngas	100	3.7	0.0029	0.01086	0	0.0109	0.048
	Mixed Syngas	250	14.8	0.0029	0.10737	0	0.1074	0.470
	Sweet Syngas	50	22.5	0.0029	0.03256	0	0.0326	0.143
Compressor Seals	Raw Syngas	0	20.4	0.5027	0	0	0	0
	Shifted Syngas	0	3.7	0.5027	0	0	0	0
	Mixed Syngas	0	14.8	0.5027	0	0	0	0
	Sweet Syngas	0	22.5	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	20.4	0.0386	0	0	0	0
	Shifted Syngas	0	3.7	0.0386	0	0	0	0
	Mixed Syngas	0	14.8	0.0386	0	0	0	0
	Sweet Syngas	0	22.5	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	20.4	0.2293	0.93554	0	0.9355	4.0977
	Shifted Syngas	4	3.7	0.2293	0.03434	0	0.0343	0.1504
	Mixed Syngas	8	14.8	0.2293	0.27167	0	0.2717	1.1899
	Sweet Syngas	4	22.5	0.2293	0.20596	0	0.2060	0.9021
Sample Connections	Raw Syngas	2	20.4	0.033	0.01346	0	1.3E-02	0.0590
	Shifted Syngas	2	3.7	0.033	0.00247	0	2.5E-03	1.1E-02
	Mixed Syngas	2	14.8	0.033	0.00977	0	9.8E-03	0.0428
	Sweet Syngas	2	22.5	0.033	0.01482	0	1.5E-02	0.0649
Total CO							2.157	9.446

Hydrogen Sulfide

Fugitive Source	Process Stream	Component Count	H2S Conc %v	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
				lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	0.58	0.0089	0.00519	0	5.2E-03	0.023
	Shifted Syngas	50	0.61	0.0089	0.00269	0	2.7E-03	0.012
	Mixed Syngas	100	1.10	0.0089	0.00978	0	9.8E-03	0.043
	Sweet Syngas	20	2.8E-06	0.0089	5.0E-09	0	5.0E-09	2.2E-08
Flanges	Raw Syngas	250	0.58	0.0029	0.00423	0	4.2E-03	0.019
	Shifted Syngas	100	0.61	0.0029	0.00176	0	1.8E-03	7.7E-03
	Mixed Syngas	250	1.10	0.0029	0.00797	0	8.0E-03	0.035
	Sweet Syngas	50	2.8E-06	0.0029	4.1E-09	0	4.1E-09	1.8E-08
Compressor Seals	Raw Syngas	0	0.58	0.5027	0	0	0	0
	Shifted Syngas	0	0.61	0.5027	0	0	0	0
	Mixed Syngas	0	1.10	0.5027	0	0	0	0
	Sweet Syngas	0	2.8E-06	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.58	0.0386	0	0	0	0
	Shifted Syngas	0	0.61	0.0386	0	0	0	0
	Mixed Syngas	0	1.10	0.0386	0	0	0	0
	Sweet Syngas	0	2.8E-06	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.58	0.2293	0.02675	0	0	0
	Shifted Syngas	4	0.61	0.2293	0.00555	0	0	0
	Mixed Syngas	8	1.10	0.2293	0.02016	0	0	0
	Sweet Syngas	4	2.8E-06	0.2293	2.6E-08	0	0	0
Sample Connections	Raw Syngas	2	0.58	0.033	0.00039	0	3.9E-04	1.7E-03
	Shifted Syngas	2	0.61	0.033	0.00040	0	4.0E-04	1.7E-03
	Mixed Syngas	2	1.10	0.033	0.00073	0	7.3E-04	3.2E-03
	Sweet Syngas	2	2.8E-06	0.033	1.9E-09	0	1.9E-09	8.2E-09
Total Hydrogen Sulfide							0.086	0.375

No Control Efficiency claimed for components in sweet syngas service due to low concentration.

Ammonia

Fugitive Source	Process Stream	Component Count	NH3 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
			%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Raw Syngas	100	0.0012	0.0089	1.0E-05	0	1.0E-05	4.5E-05
	Shifted Syngas	50	0.0012	0.0089	5.2E-06	0	5.2E-06	2.3E-05
	Mixed Syngas	100	0.0012	0.0089	1.0E-05	0	1.0E-05	4.5E-05
	Sweet Syngas	20	0	0.0089	0	0	0	0
Flanges	Raw Syngas	250	0.0012	0.0029	8.4E-06	0	8.4E-06	3.7E-05
	Shifted Syngas	100	0.0012	0.0029	3.4E-06	0	3.4E-06	1.5E-05
	Mixed Syngas	250	0.0012	0.0029	8.4E-06	0	8.4E-06	3.7E-05
	Sweet Syngas	50	0	0.0029	0	0	0	0
Compressor Seals	Raw Syngas	0	0.0012	0.5027	0	0	0	0
	Shifted Syngas	0	0.0012	0.5027	0	0	0	0
	Mixed Syngas	0	0.0012	0.5027	0	0	0	0
	Sweet Syngas	0	0	0.5027	0	0	0	0
Pump Seals	Raw Syngas	0	0.0012	0.0386	0	0	0	0
	Shifted Syngas	0	0.0012	0.0386	0	0	0	0
	Mixed Syngas	0	0.0012	0.0386	0	0	0	0
	Sweet Syngas	0	0	0.0386	0	0	0	0
Relief Valves	Raw Syngas	20	0.0012	0.2293	5.3E-05	0	5.3E-05	2.3E-04
	Shifted Syngas	4	0.0012	0.2293	1.1E-05	0	1.1E-05	4.7E-05
	Mixed Syngas	8	0.0012	0.2293	2.1E-05	0	2.1E-05	9.3E-05
	Sweet Syngas	4	0	0.2293	0	0	0	0
Sample Connections	Raw Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Shifted Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Mixed Syngas	2	0.0012	0.033	7.7E-07	0	7.7E-07	3.4E-06
	Sweet Syngas	2	0	0.033	0	0	0	0
Total Ammonia							1.3E-04	5.8E-04

Notes:

1 Component counts are preliminary subject to change during detailed project engineering.
2 Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3 Relief valves discharge to flare.
4 No LDAR program is required for syngas streams, therefore, no control efficiency assumed.

NAME Fugitive Emissions - Wet Sulfuric Acid Units Unit ID: FUG - WSA

Summary of Fugitive Vapor Emissions for Wet Sulfuric Acid Process

H2S

Fugitive Source	Process Stream	Component Count		H2S Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	10	20	44.00	0.00890	0.0783	0	0.0783	0.3430
Flanges	Acid Gas	100	200	44.00	0.00290	0.2552	0	0.2552	1.1178
Compressor Seals	Acid Gas	0	0	44.00	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	44.00	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	2	4	44.00	0.22930	0.4036	0	0.4036	1.7676
Sample Connections	Acid Gas	4	8	44.00	0.03300	0.1162	0	0.11616	0.5088
Total H2S								0.8532	3.7372

SO2

Fugitive Source	Process Stream	Component Count		SO2 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	6.20	0.00890	0	97	0.0000	0.0000
Flanges	Acid Gas	20	40	6.20	0.00290	0.0072	97	0.0002	0.0009
Compressor Seals	Acid Gas	0	0	6.20	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	6.20	0.03860	0	85	0.0000	0.0000
Relief Valves	Acid Gas	0	0	6.20	0.22930	0	100	0.0000	0.0000
Sample Connections	Acid Gas	4	8	6.20	0.03300	0.0164	97	0.00049	0.0022
Total SO2								0.0007	0.0031

SO3

Fugitive Source	Process Stream	Component Count		SO3 Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	3.30	0.00890	0.0000	0	0.0000	0.0000
Flanges	Acid Gas	30	60	3.30	0.00290	0.0057	0	0.0057	0.0251
Compressor Seals	Acid Gas	0	0	3.30	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	3.30	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	0	0	3.30	0.22930	0.0000	0	0.0000	0.0000
Sample Connections	Acid Gas	3	6	3.30	0.03300	0.0065	0	0.00653	0.0286
Total SO3								0.0123	0.0538
Total SO3 as H2SO4								0.01504	0.0659

H2SO4 Vapor

Fugitive Source	Process Stream	Component Count		Acid Conc	Emission Factors	Uncontrolled Emissions	Control Efficiency	Controlled Emissions	
		Per Train	Total	%v	lb/hr/component	lb/hr	%	lb/hr	TPY
Valves	Acid Gas	0	0	3.60	0.00890	0.0000	0	0.0000	0.0000
Flanges	Acid Gas	10	20	3.60	0.00290	0.0021	0	0.0021	0.0091
Compressor Seals	Acid Gas	0	0	3.60	0.50270	0	0	0.0000	0.0000
Pump Seals	Acid Gas	0	0	3.60	0.03860	0	0	0.0000	0.0000
Relief Valves	Acid Gas	0	0	3.60	0.22930	0.0000	0	0.0000	0.0000
Sample Connections	Acid Gas	1	2	3.60	0.03300	0.0024	0	0.00238	0.0104
Total H2SO4								0.0045	0.0196
Total H2SO4 including SO3								0.020	0.0854

Notes:

1. Component counts are preliminary subject to change during detailed project engineering.
2. Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3. Relief valves discharge to flare.

NAME Fugitive Emissions - Greenhouse Gas Emissions Only (from Gasification/SNG and from WSA)

Unit ID: FUG & FUG-WSA

CO2 in WSA (FUG-WSA)

Emission Source	Source Process Stream	Total Component Count	Conc %w	Average Emissions Factor lb/hr	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Acid Gas	20	**42.90**	**0.00890**	0.076		0.0764	0.3345
Flanges	Acid Gas	200	**42.90**	**0.00290**	0.249		0.2488	1.0898
Compressor Seals	Acid Gas	0	**42.90**	**0.50270**	0.000		0.0000	0.0000
Pump Seals	Acid Gas	0	**42.90**	**0.03860**	0.000		0.0000	0.0000
Relief Valves	Acid Gas	4	**42.90**	**0.22930**	0.393		0.3935	1.7234
Sample Connections	Acid Gas	8	**42.90**	**0.03300**	0.113		0.1133	0.4961
Total					**0.832**		**0.8319**	**3.644**

Carbon Dioxide from FUG

Emission Source	Source Process Stream	Component Count	CO2 Conc %v	Emissions Factor lb/hr/component (discounted by %v)	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Raw Syngas	100	6.2	0.001	0.055		0.0554	0.243
	Shifted Syngas	50	23.6	0.002	0.105		0.1049	0.460
	Mixed Syngas	100	32.2	0.003	0.287		0.2867	1.256
	Sweet Syngas	20	6.3	0.001	0.011		0.0112	0.049
	CO2	30	99.0	0.009	0.264		0.2643	1.158
Flanges	Raw Syngas	250	6.2	0.000	0.045		0.0451	0.198
	Shifted Syngas	100	23.6	0.001	0.068		0.0684	0.299
	Mixed Syngas	250	32.2	0.001	0.234		0.2335	1.023
	Sweet Syngas	50	6.3	0.000	0.009		0.0092	0.040
	CO2	60	99.0	0.003	0.172		0.1723	0.754
Compressor Seals	Raw Syngas	0	6.2	0.031	0.000	85	0.0000	0.000
	Shifted Syngas	0	23.6	0.119	0.000	85	0.0000	0.000
	Mixed Syngas	0	32.2	0.162	0.000	85	0.0000	0.000
	Sweet Syngas	0	6.3	0.032	0.000	85	0.0000	0.000
	CO2	16	99.0	0.498	7.963	85	1.1944	5.232
Pump Seals	Raw Syngas	0	6.2	0.002	0.000		0.0000	0.000
	Shifted Syngas	0	23.6	0.009	0.000		0.0000	0.000
	Mixed Syngas	0	32.2	0.012	0.000		0.0000	0.000
	Sweet Syngas	0	6.3	0.002	0.000		0.0000	0.000
	CO2	0	99.0	0.038	0.000		0.0000	0.000
Relief Valves	Raw Syngas	20	6.2	0.014	0.286		0.2856	1.251
	Shifted Syngas	4	23.6	0.054	0.216		0.2162	0.947
	Mixed Syngas	8	32.2	0.074	0.591		0.5909	2.588
	Sweet Syngas	4	6.3	0.014	0.058		0.0580	0.254
	CO2	3	99.0	0.227	0.681		0.6810	2.983
Sample Connections	Raw Syngas	2	6.2	0.002	0.004		0.0041	0.018
	Shifted Syngas	2	23.6	0.008	0.016		0.0156	0.068
	Mixed Syngas	2	32.2	0.011	0.021		0.0213	0.093
	Sweet Syngas	2	6.3	0.002	0.004		0.0042	0.018
	CO2	2	99.0	0.033	0.065		0.0653	0.286
Total					**11.091**		**4.3876**	**19.218**

48.577

Methane from FUG

Emission Source	Source Process Stream	Component Count	CH4 Conc %v	Emissions Factor lb/hr/component	Uncontrolled Total Emissions lb/hr	Control Efficiency %	Controlled Total Emissions lb/hr	Controlled Total Emissions tpy
Valves	Raw Syngas	100	0.025	0.000	0.000	97	0.0000	0.000
	Shifted Syngas	50	0.025	0.000	0.000	97	0.0000	0.000
	Mixed Syngas	100	0.060	0.000	0.001	97	0.0000	0.000
	Sweet Syngas	20	0.063	0.000	0.000	97	0.0000	0.000
	Fuel Gas	25	94.2	0.008	0.210	97	0.0063	0.028
	SNG	10	94.2	0.008	0.084	97	0.0025	0.011
Flanges	Raw Syngas	250	0.025	0.000	0.000	97	0.0000	0.000
	Shifted Syngas	100	0.025	0.000	0.000	97	0.0000	0.000
	Mixed Syngas	250	0.060	0.000	0.000	97	0.0000	0.000
	Sweet Syngas	50	0.063	0.000	0.000	97	0.0000	0.000
	Fuel Gas	30	94.2	0.003	0.082	97	0.0025	0.011
	SNG	20	94.2	0.003	0.055	97	0.0016	0.007
Compressor Seals	Raw Syngas	0	0.025	0.000	0.000	99.7	0.0000	0.000
	Shifted Syngas	0	0.025	0.000	0.000	99.7	0.0000	0.000
	Mixed Syngas	0	0.060	0.000	0.000	99.7	0.0000	0.000
	Sweet Syngas	0	0.063	0.000	0.000	99.7	0.0000	0.000
	Fuel Gas	0	95	0.008	0.000	99.7	0.0000	0.000
	Fuel Gas	0	94.2	0.474	0.000	99.7	0.0000	0.000
	SNG	4	94.2	0.474	1.894	99.7	0.0057	0.025
Pump Seals	Raw Syngas	0	0.025	0.000	0.000	85	0.0000	0.000
	Shifted Syngas	0	0.025	0.000	0.000	85	0.0000	0.000
	Mixed Syngas	0	0.060	0.000	0.000	85	0.0000	0.000
	Sweet Syngas	0	0.063	0.000	0.000	85	0.0000	0.000
	Fuel Gas	0	94.2	0.036	0.000	85	0.0000	0.000
	SNG	0	94.2	0.036	0.000	85	0.0000	0.000
Relief Valves	Raw Syngas	20	0.025	0.000	0.001	99.7	0.0000	0.000
	Shifted Syngas	4	0.025	0.000	0.000	99.7	0.0000	0.000
	Mixed Syngas	8	0.060	0.000	0.001	99.7	0.0000	0.000
	Sweet Syngas	4	0.063	0.000	0.001	99.7	0.0000	0.000
	Fuel Gas	1	94.2	0.216	0.216	99.5	0.0011	0.005
	SNG	2	94.2	0.216	0.432	99.5	0.0022	0.009
Sample Connections	Raw Syngas	2	0.025	0.000	0.000	97	0.0000	0.000
	Shifted Syngas	2	0.025	0.000	0.000	97	0.0000	0.000
	Mixed Syngas	2	0.060	0.000	0.000	97	0.0000	0.000
	Sweet Syngas	2	0.063	0.000	0.000	97	0.0000	0.000
	Fuel Gas	0	94.2	0.031	0.000	97	0.0000	0.000
	SNG	1	94.2	0.031	0.031	97	0.0009	0.004
Total					**2.977**		**0.0228**	**0.100**

TPY CO_2e from FUG= 21.32

Notes:

1 Component counts are preliminary subject to change during detailed project engineering.
2 Emissions factors and control efficiencies from TCEQ 28VHP LDAR Program.
3 Relief valves discharge to flare

Coal/Coke Truck Unloading Operation

Note: Truck and Rail unloading is not simultantious, During Trucking reciepts, the below sources replace 12g, h, I, j and k.

PM$_{10}$ EMISSIONS		Process Rate		Emission Factor		Control Type	Control Efficiency	Operating Hours/yr	Operating Hours/day	Max. Hour Emissions	Average Daily	Annual Emissions
Unit ID	Name									lb/hr	lb/hr	TPY
012 Y	Transfer tower from Truck/Rail conveyor to pile conveyor	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	8,760	24	0.039	0.039	0.17
012 Z	Truck Bay 1 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.039	0.019	0.046
012 AA	Truck hopper to conveyor	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.039	0.019	0.046
012 AB	Truck Bay 2 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.039	0.019	0.046
012 AC	Truck Bay 3 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.039	0.019	0.046

PM$_{2.5}$ EMISSIONS		Process Rate		Emission Factor		Control Type	Control Efficiency	Operating Hours/yr	Operating Hours/day	Max. Hour Emissions	Average Daily	Annual Emissions
Unit ID	Name									lb/hr	lb/hr	TPY
012 Y	Transfer tower from Truck/Rail conveyor to pile conveyor	1,500	ACFM	0.175	GR/ACF	DUST EXTRACTION SYSTEM	99.14%	8,760	24	0.019	0.019	0.085
012 Z	Truck Bay 1 dump to Hopper	1,500	ACFM	0.175	GR/ACF	DUST EXTRACTION SYSTEM	99.14%	2,365	12	0.019	0.0097	0.023
012 AA	Truck hopper to conveyor	1,500	ACFM	0.175	GR/ACF	DUST EXTRACTION SYSTEM	99.14%	2,365	12	0.019	0.0097	0.023
012 BB	Truck Bay 2 dump to Hopper	1,500	ACFM	0.175	GR/ACF	DUST EXTRACTION SYSTEM	99.14%	2,365	12	0.019	0.0097	0.023
012 CC	Truck Bay 3 dump to Hopper	1,500	ACFM	0.175	GR/ACF	DUST EXTRACTION SYSTEM	99.14%	2,365	12	0.019	0.0097	0.023
												0.18

TOTAL PARTICULATE EMISSIONS		Process Rate		Emission Factor		Control Type	Control Efficiency	Operating Hours/yr	Operating Hours/day	Max. Hour Emissions	Average Daily	Annual Emissions
Unit ID	Name									lb/hr	lb/hr	TPY
012 Y	Transfer tower from Truck/Rail conveyor to pile conveyor	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	8,760	24	0.0386	0.0386	0.17
012 Z	Truck Bay 1 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.0386	0.019	0.046
012 AA	Truck hopper to conveyor	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.0386	0.019	0.046
012 BB	Truck Bay 2 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.0386	0.019	0.046
012 CC	Truck Bay 3 dump to Hopper	1,500	ACFM	2.50	GR/ACF	DUST EXTRACTION SYSTEM	99.88%	2,365	12	0.0386	0.019	0.046
												0.35

Comments:

PM10 AND PM2.5 Inlet grain loading factor (gr/acfm) and control efficiency provided by vendor.
Total PM Inlet grain loading factor (gr/acfm) calculated from NSPS Subpart Y outlet grain loading requirement of 0.01 gr/dscf PM

CALCULATION SHEET

Emission Unit	**Emission Description**
FUG-ROAD-C (Coal Trucks)	Fugitive Dust: Paved Road Truck Traffic for Coal/Coke delivery by Truck

Calculation Methodology

AP-42 Chapter 13, Section 2.1 : Miscellaneous Sources, Paved Roads
Max Hourly and Daily Emissions calculated using equation (1)

$$\boxed{E = k(sL)^{0.91} \times (W)^{1.02}}$$

Annual Emissions calculated using equation (2)

$$\boxed{E_{ext} = \left[k(sL)^{0.91} \times (W)^{1.02}\right](1 - P/4N)}$$

k factor from Table 13.2.1-1
PM = 0.011
PM10 = 0.0022
PM2.5 = 0.00054
Road Surface Silt Loading, sL = 1.0 g/m^2 (Conservative value considering planned frequent watering)
EmptyTruck weight = 9.7 tons
Full Truck weight = 41.7 tons
"Wet" days, P = 117 days
Number of days in averaging period, N = 365

Calculation of Potential Emissions:

Average Round-Trip Distance:	0.479	mile/trip	"Wet" Days, P:	117	days	
Road Surface Silt Loading, sL:	1.0	g/m^2	Days in Ave. Period, N:	365	days	
Average Truck Weight, W:	25.7	tons	Highest Day Wet Coal	249.1	tons/hr	50% plant capacity
Particle Size Multiplier, k:	0.0022	PM10	Carried each Load:	32.0	tons/truck	
Particle Size Multiplier, k:	0.00054	PM2.5	Truck Trips:	186.8	trip/day	
Particle Size Multiplier, k:	0.011	PM	Truck Trips:	100.9	daily trip (yr avg)	54% of daily trips
			Control Efficiency for Watering:	90%		

Potential PM10 Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.0225	0.54	0.0906

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.0055	0.13	0.0222

Potential PM Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-C (Coal Trucks)	0.1124	2.70	0.4531

Emission Unit	**Emission Description**
FUG-ROAD-S (Slag)	Fugitive Dust: Paved Roads for Slag Truck Hauling

Calculation Methodology

AP-42 Chapter 13, Section 2.1 : Miscellaneous Sources, Paved Roads
Max Hourly and Daily Emissions calculated using equation (1) emissions factor

$$\boxed{E = k(sL)^{0.91} \times (W)^{1.02}}$$

Annual Emissions calculated using equation (2) emissions factor

$$\boxed{E_{ext} = \left[k(sL)^{0.91} \times (W)^{1.02}\right](1 - P/4N)}$$

k factor from Table 13.2.1-1
PM = 0.011
PM10 = 0.0022
PM2.5 = 0.00054
EmptyTruck weight = 9.7 tons
Load each trip = 20 tons
"Wet" days, P = 117 days
Number of days in averaging period, N = 365

Trip Distance = 600 ft, each way in process block (normal). Additionally, if slag hauled to coal yard temporary storage, then it must travel 900 feet offsite to coal yard area, then it travels 1100 feet in coal yard to drop off and 1100 feet in coal yard to pick up. (worse-case total = 600+600+1100+1100 excluding the portion of travel "offsite"/outside the fenceline.)

Emissions calculated = Emissions factor (lb/vmt) * trip distance (miles) * number of trips * (1-control efficiency)

Calculation of Potential Emissions:

Total Round-Trip Distance:	0.644	mile/trip	"Wet" Days, P:	117	days
Road Surface Silt Loading, sL:	1.0	g/m^2	Days in Ave. Period, N:	365	days
Average Truck Weight, W:	19.7	tons	Slag Production:	43.08	tons/hr
Particle Size Multiplier, k:	0.0022	PM10	Carried each Load:	20.0	tons/truck
Particle Size Multiplier, k:	0.00054	PM2.5	Truck Trips:	82.7	trip/day (includes 31 trucks/day contingency)
Particle Size Multiplier, k:	0.011	Total PM	Control Efficiency for Watering:	90%	

Potential PM10 Emissions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0102	0.24	0.0411

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0025	0.06	0.0101

Potential Total PM Emisions:

EP	Max lb/hr	lb/day	tpy
FUG-ROAD-S (Slag)	0.0510	1.22	0.2056

Process Road Segment

PM10	0.0036	lb/hr
PM2.5	0.00088	lb/hr
Total PM	0.01801	lb/hr

Coal Yard Road Segment

PM10	0.0066	lb/hr
PM2.5	0.0016	lb/hr
Total PM	0.0330	lb/hr

CALCULATION SHEET

Emission Unit	**Emission Description**
EU-034A	Handling (Drop) emissions for handling/loading Slag at temp. Storage pile.

Calculation Methodology

AP-42 Chapter 13, Section 2.4:Aggregate Handling and Storage Piles
Uncontrolled Emissions per handling step calculated using equation (1)

$$E = k\left(0.0032\right)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

$$E = k\left(0.0032\right)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where:
E = emissions factor in lbs emissions per ton aggregate handled
U = mean wind speed, mph
M = material moisture content
k = particle size multplier (dimensionless)
Total PM k = 0.74
PM10 k = 0.35
PM2.5 k = 0.053

Assume that slag dumped from trucks coming from process is so wet that there are no emissions.

Also assume when/if slag is initially picked up by front end loader and piled or moved within storage site that it is still wet enough to not have emissions
Then assume slag is picked up by front end loader and loaded into truck for haulting out (1 handling step)
Assume watering used to keep slag wet. Control effectiveness of watering reflected in assumed moisture content.

Calculation of Potential Emissions:

Number of Drops(handling steps)	1.000	drops	Maximum daily slag	1,034	tons/day max
Mean wind speed	8.0	mph	Max hourly slag	43.08	tons/hr
Material Moisture content	15.00	%	Annual Slag Production:	720.0	tons/day annual average
Particle Size Multiplier, k:	0.35	PM10	Average hourly slag	30	tons/hr annual average
Particle Size Multiplier, k:	0.053	PM2.5	Hours per yr of activity	8760.0	
Particle Size Multiplier, k:	0.74	Total PM	Control Efficiency for Watering	Addressed by moisture content assumption	

Potential PM10 Emissions:

EP	Max lb/hr	Max lb/day	tpy
EU-034A	0.0053	0.13	0.0161

Potential PM2.5 Emisions:

EP	Max lb/hr	lb/day	tpy
EU-034A	0.0008	0.02	0.0024

Potential Total PM Emisions:

EP	Max lb/hr	lb/day	tpy
EU-034A	0.0112	0.27	0.0341

EU-034C Emission Calculation for Front-End Loader and Slag truck Activity on the temp. Slag storage pad/pile

Although Storage Pad is paved, assume it is partially covered in slag, calculate emissions assuming unpaved road equation.

Description of Vehicles	**Load Size tons**	**Vehicle Weight Empty tons**	**Average Vehicle Weight tons**	**Daily Slag (annual average) tons/day**	**Max Slag per day tons/day**	**Miles per trip Mile/trip**	**Maximum Daily Trips/day**	**Ave Annual Trips/day**	**Maximum VMT Miles/day**	**Ave. Annual VMT Miles/day**
Front End Loader	20	32.66	26.33	1,440	2,068	0.0142	103.4	72	1.469	1.023

Note: Slag handled is slag production assuming that slag is either delivered to or picked up from the storage pad each day. (Not being dropped off all day and being picked up all day on the same day).
Assume each trip of front end loader trip is 75 feet round trip (1/4 width of pad times 2)

	Average Vehicle weigh (tons)	**Uncontrolled Emissions factor (lbs total PM/VMT)**	**Uncontrolled Emissions factor (lbs PM10/VMT)**	**Uncontrolled Emissions factor (lbs PM2.5/VMT)**	**Control Efficiency**	**Max daily lb/hr Total PM**	**Max daily lb/hr PM10**	**Max daily lb/hr PM2.5**	
Front End Loader/dozer	26.33	2.287	0.426	0.043	90%	0.014	0.003	0.000	**Front End Loader**
					Total	**0.014**	**0.003**	**0.000**	
						Max Annual Tons/yr Total PM	**Max Annual Tons/yr PM10**	**Max Annual Tons/yr PM2.5**	
						0.007	0.001	0.000	**Front End Loader**
					Total	**0.007**	**0.001**	**0.000**	

UNPAVED ROADS EQUATIONS Industrial Roads - AP42 13.2.4 (equations 1a and 2)

$$E = k * \left(s/12\right)^{a} * \left(W/3\right)^{b}$$

$$E_{ext} = E\left(\frac{365-P}{365}\right)$$

E = size specific emission factor (lbs/VMT)
k = particle size multiplier for particle size range (lb/VMT)
s = surface material silt content (%)
a = constant based on size of particulate
b = constant based on size of particulate
W = Vehicle average weight (tons)
P = number of days per year with 0.01 in or more of precipitation

INPUTS TO EQUATION/CALCULATIONS	Total PM	PM10	PM2.5	
k	4.9	1.5	0.15	lb/vmt
s	1	1	1	%
a	0.7	0.9	0.9	
b	0.45	0.45	0.45	
P	117	117	117	days/yr

Indiana Gasification, LLC Spencer County Facility

Emission Unit:

FUG-SF6 Emission Estimate for Fugitive Emissions of SF_6 from Circuit Breakers

The IG facility will include a switchyard with circuit breakers that include sulfur hexafluoride (SF_6), a greenhouse gas, as a gaseous dielectric.
The circuit breakers will be totally enclosed and pressurized.
Fugitive emissions are estimated as 1% leakage per year.

Emission Calculation

Number of circuit breal	6	
Amount of SF_6 in each	100	lbs
Assumed leak rate:	1%	
Emissions (lb/yr):	6	lbs/yr
GWP of SF_6:	23,900	
CO2e (tons/yr):	71.7	tons/yr

Summary of Indiana Gasification Plant Total Particulate Emissions

Emissions Unit Number	Source Name	Total Particulate	Same as Estimated PM10	Basis of Total PM Estimate
1	Syngas Hydrocarbon Flare	0.44	Yes	Note 1
2	Acid Gas Flare	0.01	Yes	Note 1
5	Auxiliary Boilers (A-B)	5.62	Yes	Note 1
7	Acid Gas Recovery Unit (A-B)	2.46	Yes	Note 1
8	Gasifier Preheat Burners (A-E)	0.04	Yes	Note 1
9	Emergency Diesel Generators (A-B)	0.00	Yes	Note 2
10	Emergency Firewater Pumps Diesel Engines (A-C)	0.01	Yes	Note 2
11	Process Area Solid Feedstock Handling (coal/pet coke)	6.35	Yes	Note 3
12 (A-X)	Incoming Solid Feedstock Handling (coal/petcoke) (A-X)	#REF!	No	Note 4
13	Rod Mill (A-D)	0.44	Yes	Note 3
15	Wet Sulfuric Acid Plant (WSA) (A-B)	42.59	Yes	Note 5
16A	Cooling Tower - ASU	0.90	Yes	Note 6
16B	Cooling Tower - Main	6.65	Yes	Note 6
17	ASU Molecular Sieve Regeneration (A-B)	0.22	Yes	Note 2
23	Slag Sump (A-E)	- -	n/a	
24	Methanol De-Inventory Tank	- -	n/a	
25	Fresh Methanol Storage Tank	- -	n/a	
26	Sour Water Stripper Surge Tank	- -	n/a	
27	Sulfuric Acid Storage Tank (A-F)	0.00	Yes	Note 5
29	Diesel Fuel Storage Tank	- -	n/a	
30	Gasoline Fuel Storage Tank	- -	n/a	
31	Triethylene Glycol Storage Tank	- -	n/a	
32	ZLD Spray Dryer	0.51	Yes	Note 3
FUG	Fugitive Emissions - Gasification, Shift Conversion, AGR, Methanation	- -	n/a	
FUG-WSA	Fugitive Emissions - WSA	- -	n/a	
FUG-Road	Fugitive Emissions - Plant Haul Roads	2.63	No	Note 7
	Total	**#REF!**		

Note 1 Combustion Sources: PM10 Emissions for combustion sources have been calculated using particulate factors for filterable and condensible particulate from AP42. These factors are for total particulate, therefore their use for PM10 is conservative, and result in total PM = PM10.

Note 2 Engineered Equipment: These sources have PM10 based on vendor or design engineering estimate of total particulate conservatively assuming all PM is PM10. Therefore, estimate of total particulate equals PM10 estimate.

Note 3 Baghouse controlled sources: PM10 is estimated using design total particulate grain loading on outlet of baghouse. All outlet PM is conservatively assumed to be PM10, therefore total PM = PM10.

Note 4 Particulate sources using various AP42 or other equations (aggregate handling, roadway, wind erosion): These sources calculate emissions using complex equations based on silt level, vehicle weight, wind speed and other parameters. However, they all contain a "particle size multiplier" factor unique to each PM particle size range. Other than this factor, the remainder of the equation and paramaters are the same for aggregate handling and wind erosion. Therefore, total PM has been calculated by multiplying estimated PM10 by the ratio of the total PM factor: PM10 factor. For dozer-related dust, the equation also includes additional exponents which differ for different particle sizes. Therefore total PM has been calculated using the full equation and the applicable factors and exponents. Documentation of these total PM estimates are provided on separate spreadsheets.

Note 5 Sulfuric Acid Mist Sources: The WSA particulate consists predominantly of condensible sulfuric acid mist. This condensible particulate is all assumed to be PM2.5. Therefore, total PM=PM10=PM2.5. Additionally, there is a small amount of PM from combustion, however, as explained above in Note 1, for combustion PM, total PM is also equal to PM10.

Note 6 Cooling tower particulate: PM from cooling towers is based on total dissolved solids in the cooling water. This calculation gives total particulate emissions. IG has conservatively assumed that all the particulate is PM10. Therefore total PM = PM10.

Note 7 This represents the PM10 figure from the original application (see Appendix B, page H1) multiplied by a PM-size multiplier of 5. (See AP-42, Chapter 13.2, Table 13.2.1-1).

8,339,799.29

Basis:	**100%w Coal with Gasifier Methanol Startups**
4	Operating GE Quench Gasifiers (design capacity x 1.25)
10,401	STPD dry coal (design capacity x 1.25)
12,968	BTU/lb dry HHV/lb coal design
11,240	MMBTU/hr HHV coal (design capacity x 1.25)
3.66	%wt dry sulfur in coal during normal operation
600	MMSCFD H2+CO2 Total Raw Syngas from Gasifiers (design capacity x 1.25)
154	MMSCFD SNG Gross Production (design capacity x 1.25)
302.2	MMSCFD CO2 Captured
0	MMSCFD CO2 to EOR Pipeline
1,164	STPD 100%w H2SO4

		Installed	Operating	Preliminary	Operating Rate		Estimated	Mercury			Lead		
EPN #	Emission Units	Number of Stacks	Number of Stacks	Stack Height feet	Rating	Units	Annual Operating Hours	lb/MMBTU	lb/hr	Tons/yr	lb/MMBTU	lb/hr	Tons/yr
001	Gasifier Startup Flare Emissions **(methanol fuel)** - 90 per year at 90 min	1	1	300	862	MMBtu/h HHV	8760						
001	Syngas Flare - Nat Gas Pilots	1	1	300	0.27	MMBtu/h HHV	8760	1.65E-06	4.376E-07	0.0000019	2.90E-06	7.69E-07	0.0000034
002	Acid Gas Flare - Nat Gas Pilots	1	1	300	0.27	MMBtu/h HHV	8760	1.65E-06	4.376E-07	0.0000019	2.90E-06	7.69E-07	0.0000034
005	Auxiliary Boiler, Full Load Operation - black plant su (nat gas fuel)	1	1	200	816	MMBtu/h HHV	8760	2.55E-07	2.081E-04	0.0009072	4.90E-07	4.00E-04	0.0017447
005	Auxiliary Boiler, Full Load Operation (SNG or Nat Gas)	1	1	200	816	MMBtu/h HHV	8760	1.65E-06	1.347E-03	0.0058725	2.90E-06	2.37E-03	0.0103217
005	Auxiliary Boiler, Half Load Operation (SNG or Nat Gas)	1	1	200	408	MMBtu/h HHV	0	1.65E-06	6.735E-04	0.0029363	2.90E-06	1.18E-03	0.0051608
008	Gasifier Preheat Burners - black plant su (nat gas fuel)	5	5	200	35	MMBtu/h HHV	8760	2.55E-07	8.922E-06	0.0000389	4.90E-07	1.72E-05	0.0000748
008	Gasifier Preheat Burners (one operating 8 months per year, SNG or NG fuel	5	1	200	18	MMBtu/h HHV	8760	1.65E-06	2.970E-05	0.0001295	2.90E-06	5.22E-05	0.0002276
009	Emergency Diesel Generators (2 units each tested 1 hour weekly)	2	1	20	1,341	hp	500						
010	Diesel Fire Water Pump Engine (3 units each tested 1 hour weekly)	3	1	20	575	hp	500						
011	Coal Conveying and Feed Bins Dust Control System Vents	2	1	200	Rated in terms of Plant Capacity		8760		1.244E-06	0.0000054		2.42E-04	0.0010546
012	Coal Unloading and Storage (Barge, Rail, Truck)									0.0000000			0.0000000
013	Rod Mill Vent Stacks	4	4	125	Rated in terms of Plant Capacity		8760			0.0000000			0.0000000
032	ZLD Spray Drier Stack	1	1	100	5.6	MMBtu/h HHV	8760	1.65E-06	9.294E-06	0.0000405	2.90E-06	1.63E-05	0.0000712
033	ZLD Inert Gas Vent	1	1	100	Rated in terms of Plant Capacity		8760		1.404E-07	0.0000006			
015	WSA Preheat	2	1	200	35.0	MMBtu/h HHV	8760	1.65E-06	5.775E-05	0.0002518	2.90E-06	1.02E-04	0.0004425
015	WSA Stack - black plant su	2	1	213	291	stpd 100% H2SO4	8760		8.348E-11	0.0000000			
015	WSA Stack - One Unit Operation	2	1	213	582	stpd 100% H2SO4	8760		1.670E-10	0.0000000			
015	WSA Stack - Two Unit Operation	2	2	213	1,164	stpd 100% H2SO4	8760		3.339E-10	0.0000000			
16a	Cooling Tower -ASU	6	6	65	Rated in terms of Plant Capacity		8760						
16b	Cooling Tower -Main	24	24	65	Rated in terms of Plant Capacity		8760						
017	ASU Molecular Sieve Regeneration Vents	2	Int	60	Rated in terms of Plant Capacity		8760						
024	Methanol Storage Scrubber Vent Stack	1	Int	30	Rated in terms of Plant Capacity		8760						
	Fugitive Emissions - Gasification, Shift Conversion, Rectisol, Methanation	NA	NA				8760						
	Fugitive Emissions - WSA	NA	NA				8760						
	Plant Totals without CO2 Venting								**0.002336**	**0.01**		**0.004382**	**0.02**

RTO Case

007	Regen Thermal Oxidizers -black plant su, one gasifier op (nat gas fuel)	1	1	200	19.4	MMBtu/h HHV NG	8760	1.65E-06	3.202E-05	0.0001396	2.90E-06	5.63E-05	0.0002454
007	Regen Thermal Oxidizers (Note 1, Two Units Hot Standby 80% of the year, SNG	1	1	200	10.3	MMBtu/h HHV SNG	0	1.65E-06	1.705E-05	0.0000743	2.90E-06	3.00E-05	0.0001307
007	Regen Thermal Oxidizers (Note 1, One Unit Op, SNG fuel)	1	1	200	38.8	MMBtu/h HHV SNG	8760	1.65E-06	6.404E-05	0.0002792	2.90E-06	1.13E-04	0.0004907
007	Regen Thermal Oxidizers (Note 1, Two Units with common, SNG fuel)	1	1	200	77.6	MMBtu/h HHV SNG	8760	1.65E-06	1.281E-04	0.0005584	2.90E-06	2.25E-04	0.0009815
007	**RTO Totals**								0.000241	0.00		**0.000199**	0.001848
	Plant Totals with 100% CO2 to RTO								**0.002578**	**0.01**		**0.004581**	**0.02**

Notes:

1 Mercury and lead emissions are based on firing SNG in pilots, aux boiler and WSA preheater except for black plant su. RTO Hg and Pb emissions are based on SNG including black plant su.

Plant Mercury Balance for 125% of design plant operating rate

Mercury in Natural Gas:

2.60E-04	lb mercury/MMSCF natural gas	from EPA AP-42 Natural Gas Combustion
1.02E+03	BTU/SCF natural gas HHV	from EPA AP-42 Natural Gas Combustion
2.55E-07	lb mercury/MMBTU HHV natural gas	calculated

Mercury in Solids Feed to Gasifiers:

0.11	ppm dry mercury is average reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 24A
0.86	ppm dry mercury is maximum reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Resource Table 24A

	Total stph dry	**Mercury max ppm, dry**	**Mercury max lb/hr**
Coal:	433.38	0.86	0.745
Coke:	0.00	0.05	
Total coal + coke	433.38		0.745

Output streams:	max mercury	
Slag	0%	mercury in gasifier feed goes out in slag (maximum Hg to wastewater)
	0.0000	lb/hr Hg in slag
Wastewater	2%	mercury in gasifier feed goes out in gasification process wastewater
	0.0149	lb/hr Hg in gasification process wastewater
	0.5	ppbv Hg in ZLD vent gas from sulfided carbon mercury removal guaranteed
	1.4	lb-mole/hour ZLD vent gas
	7E-10	lb-moles/hour mercury in ZLD vent gas
	200.59	lb/lb-mole mercury molecular weight
	1.40E-07	lb/hr mercury in ZLD vent gas
	1.49E-02	lb/hr mercury removed by sulfided carbon
Syngas to Sulfided Carbon	98%	mercury in gasifier feed is in syngas to mercury removal
	0.7305	lb/hr Hg in syngas to mercury removal
Syngas from Sulfided Carbon	0.5	ppbv Hg in syngas from mercury removal guaranteed
	103,526	lb-moles/hr total syngas from mercury removal
	5.18E-05	lb-moles/hr Hg in syngas from mercury removal
	0.010	lb/hr mercury in syngas to Rectisol
	98.6%	mercury removal on sulfided carbon
Rectisol Treated Syngas	66,958	lb-moles/hr treated syngas from Rectisol
	-27	F Treated Rectisol syngas from absorber
	99.99998%	Hg in syngas to Rectisol assumed to be in syngas from Rectisol (worst case no accumulation in Rectisol)
	0.0104	lb/hr mercury in syngas from Rectisol
	0.77	ppbv Hg in Rectisol treated syngas
SNG	0.0104	lb/hr mercury in SNG
	2.94	ppbv Hg in SNG
	6,293	MMBTU/hr HHV SNG rate
	1.65E-06	lb Hg/MMBTU HHV SNG
Rectisol CO2	33,184	lb-moles/hr CO2 from Rectisol
	-42	F CO2 Temperature from MP Flash
	1.45E-08	lb Hg solubility/lb Methanol
	3.28E-06	Vapor pressure of Hg, mbar
	2.89E-07	ppbv Hg in CO2 from Rectisol
	1.92E-09	lb/hr Hg in CO2
Rectisol Acid Gas	3,264	lb-moles/hr acid gas from Rectisol
	-31	F acid gas temperature at the acid gas separator
	2.71E-08	lb Hg solubility/lb Methanol
	4.98E-06	Vapor pressure of Hg, mbar at -31F
	5.10E-07	ppbv Hg in acid gas from Rectisol
	3.34E-10	lb/hr Hg in acid gas
Coal Particulate Emissions	1.45	lb/hr coal dust from Coal Conveying and Feed Bins Dust Control System Vents
	1.24E-06	lb/hr mercury in coal dust from coal converying and feed bins dust control system vents
	1.09E-02	lb/yr mercury in coal dust from coal conveying and feed bins dust control system vents
	10.39	tons per year coal dust from coal unloading and storage
	1.79E-02	lb/yr mercury in coal dust from coal unloading and storage
	0.44	tons per year coal dust from rod mills
	7.57E-04	lb/yr mercury in coal dust from rod mills

Plant Lead Balance for 125% of design plant operating rate

Natural Gas Combustion

5.00E-04	lb lead/MMSCF natural gas	from EPA AP-42 Natural Gas Combustion
1.02E+03	BTU/SCF natural gas HHV	from EPA AP-42 Natural Gas Combustion
4.90E-07	lb lead /MMBTU HHV natural gas	calculated

SNG Combustion

Lead in Solids Feed to Gasifiers:

21.36	ppm dry lead is average reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal Re
167.17	ppm dry lead is maximum reported by Indiana Geological Survey 2004 Characterization of Indiana's Coal

	Total stph dry	**Lead max ppm, dry**	**Lead max lb/hr**
Coal:	433.38	167.17	144.89
Coke:	0.00	0.5	
Total coal + coke	433.38		144.89

Output streams:	**max lead**	
Slag	33%	lead in gasifier feed goes out in slag per LGTI Gasification Plant metal mass balances (2002 IG
	47.82	lb/hr lead in slag
SNG	2.90E-06	lb/MMBTU HHV SNG based on LGTI Gasification Plant metal mass balances (2002 IGCC Env
	6,293	MMBTU/hr HHV SNG rate
	0.0182	lb/hr lead in SNG
Accumulation	97.06	lb/hr lead accumulated on shift catalyst, sulfided carbon beds, sulfur guard beds, methanation

Coal Particulate Emissions	1.45	lb/hr coal dust from Coal Conveying, Storage and Feed Bins Dust Control System Vents
	2.42E-04	lb/hr lead in coal dust from coal converying, storage and feed bins dust control system vents
	2.12	lb/yr lead in coal dust from coal conveying and feed bins dust control system vents
	10.39	tons per year coal dust from coal unloading and storage
	3.47	lb/yr lead in coal dust from coal unloading and storage
	0.44	tons per year coal dust from rod mills
	0.15	lb/yr lead in coal dust from rod mills

Solid particulates Emission rate:

Emission Point Source	**cfm**	**dscfm**	**Emission Rate, lb/hr**
11a	30,000	33,760	1.4469
11b (spare)	30,000	33,760	

Notes:

Note 1: All sources (Coal & Coke Dust Collectors) will be fabric filter units with exhaust fans and will be specified to have a dust emissions limit, as measured in gr/dscf, equal to: 0.005 grains per drscf

A

esource Table 46A
Resource Table 46A

GCC Environmental Assessment by SAIC & NETL)

ironmental Assessment by SAIC & NETL)

catalyst, and liquid filters

Tank Calculation Methodology

Data

All tank information in the Indiana Gasification data workbook was provided by B&V.

Calculation Basis

Tank emissions are calculated per AP-42, Chapter 7 (September 1997 version) and URS tank calculation methodology.

Tank Characteristics

Tank color, type, height, diameter were provided by B&V. Liquid height (Hl) was conservatively assumed to be 1/2 the tank shell height. This increases the vapor space and thus the tank emissions are conservatively increased.

Bulk Liquid Characteristics

Annual Throughput was provided by B&V.

The Maximum pump rate was utilized to calculate the annual throughput for the Maximum hourly emissions case.

Temperature Parameters

The liquid bulk temperatures were provided by B&V. If the Liquid bulk temperature (Tb) was outside of the ambient temperature range, then the daily average liquid surface temperature was adjusted to be equivalent to the liquid bulk temperature (Tla =T

Vapor Pressures

Riedel and Antoine constants were used to develop vapor pressure estimates for each material. Aqueous Ammonia v.p. from Perry's 6th Ed.

Speciated Emissions

Unit ID	Tank ID	Tank Capacity	Throughput	Pva
		gal	gal / year	psia
023 A	Slag Sump	25,284	37,492,800	2.69
023 B	Slag Sump	25,284	37,492,800	2.69
023 C	Slag Sump	25,284	37,492,800	2.69
023 D	Slag Sump	25,284	37,492,800	2.69
023 E	Slag Sump	25,284	37,492,800	2.69
024	Methanol De-Inventory Tank	710,896	1,386,000	1.98
025	Fresh Methanol Storage Tank	342,005	2,000,000	1.98
026	Sour Water Stripper Surge	182,741	-	2.27
027 A	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
027 B	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
027 C	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
027 D	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
027 E	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
027 F	Sulfuric Acid Storage Tank	881,276	13,665,600	1.3E-05
028 A	Aqueous Ammonia	32,243	440,000	5.38
028 B	Aqueous Ammonia	32,243	440,000	5.38
029	Diesel	9,953	10,000	6.05
030	Gasoline	1,175	8,000	6.20

NOTE: The Sour Water Stripper Surge Tank is a flow through (constant level) tank

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 023 A
DESCRIPTION: Slag Sump
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	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Slag	Slag	
SHELL COLOR		White	White	
ROOF TYPE		Flat	Flat	
INSIDE DIAMETER	CSA:	260	260	ft
TANK SHELL HEIGHT	Hs:	13	13	ft
MAX. TANK LIQUID VOLUME	Vlx:	3,380	3,380	cf
LIQUID HEIGHT	Hl:	6.5	6.5	ft
ROOF OUTAGE HEIGHT	Hro:	0.00	0.00	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	6.50	6.50	ft
VAPOR SPACE VOLUME	Vv:	1,690	1,690	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	37,492,800	221,488,628	gal/yr
ANNUAL THROUGHPUT	Q:	892,686	5,273,539	bbl/yr
TURNOVERS PER YEAR	N:	1482.70	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	18.05	18.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	647.7	671.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	596.8	671.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	601.9	676.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	591.7	666.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.6937	14.7002	psia
VAPOR PRESSURE AT Tlx	Pvx:	3.0707	16.2478	psia
VAPOR PRESSURE AT Tln	Pvn:	2.3570	13.2768	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.71	3.0	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.04)	(0.04)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.26	0.26	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	0.19	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0076	0.0368	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0720	PRESSURE VESSEL	
VENTED VAPOR SATURATION FACTOR	Ks:	0.52	0.16	
STANDING LOSS	Ls:	174.8158	0.00	lb/yr
WORKING LOSS	Lw:	8113.7685	237741.01	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		8288.58	237,741.01	lb/yr
UNCONTROLLED TOTAL EMISSIONS (H$_2$S and Water)		0.946	27.14	lb/hr
		4.144	118.87	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Hydrogen Sulfide (TAP)	37.584	0.048

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Hydrogen Sulfide (TAP)	0.004	0.048	0.02

TANK TYPE: FIXED ROOF   Indiana Gasification   Unit ID: 023 B

DESCRIPTION: Slag Sump

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Slag	Slag	
SHELL COLOR		White	White	
ROOF TYPE		Flat	Flat	
INSIDE DIAMETER	CSA:	260	260	ft
TANK SHELL HEIGHT	Hs:	13	13	ft
MAX. TANK LIQUID VOLUME	Vlx:	3,380	3,380	cf
LIQUID HEIGHT	Hl:	6.5	6.5	ft
ROOF OUTAGE HEIGHT	Hro:	0.00	0.00	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	6.50	6.50	ft
VAPOR SPACE VOLUME	Vv:	1,690	1,690	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	37,492,800	221,488,628	gal/yr
ANNUAL THROUGHPUT	Q:	892,686	5,273,539	bbl/yr
TURNOVERS PER YEAR	N:	1482.70	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	18.05	18.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	647.7	671.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	596.8	671.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	601.9	676.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	591.7	666.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.6937	14.7002	psia
VAPOR PRESSURE AT Tlx	Pvx:	3.0707	16.2478	psia
VAPOR PRESSURE AT Tln	Pvn:	2.3570	13.2768	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.71	3.0	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.04)	(0.04)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.26	0.26	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	0.19	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0076	0.0368	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0720	PRESSURE VESSEL	
VENTED VAPOR SATURATION FACTOR	Ks:	0.52	0.16	
STANDING LOSS	Ls:	174.8158	0.00	lb/yr
WORKING LOSS	Lw:	8113.7685	237741.01	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		8288.58	237,741.01	lb/yr
UNCONTROLLED TOTAL EMISSIONS (H_2S and Water)		0.946	27.14	lb/hr
		4.144	118.87	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Hydrogen Sulfide (TAP)	37.584	0.048

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Hydrogen Sulfide (TAP)	0.004	0.048	0.02

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 023 C
DESCRIPTION: Slag Sump
Page 4 of 40 TSD App A

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Slag	Slag	
SHELL COLOR		White	White	
ROOF TYPE		Flat	Flat	
INSIDE DIAMETER	CSA:	260	260	ft
TANK SHELL HEIGHT	Hs:	13	13	ft
MAX. TANK LIQUID VOLUME	Vlx:	3,380	3,380	cf
LIQUID HEIGHT	Hl:	6.5	6.5	ft
ROOF OUTAGE HEIGHT	Hro:	0.00	0.00	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	6.50	6.50	ft
VAPOR SPACE VOLUME	Vv:	1,690	1,690	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	37,492,800	221,488,628	gal/yr
ANNUAL THROUGHPUT	Q:	892,686	5,273,539	bbl/yr
TURNOVERS PER YEAR	N:	1482.70	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	18.05	18.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	647.7	671.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	596.8	671.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	601.9	676.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	591.7	666.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.6937	14.7002	psia
VAPOR PRESSURE AT Tlx	Pvx:	3.0707	16.2478	psia
VAPOR PRESSURE AT Tln	Pvn:	2.3570	13.2768	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.71	3.0	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.04)	(0.04)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.26	0.26	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	0.19	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0076	0.0368	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0720	PRESSURE VESSEL	
VENTED VAPOR SATURATION FACTOR	Ks:	0.52	0.16	
STANDING LOSS	Ls:	174.8158	0.00	lb/yr
WORKING LOSS	Lw:	8113.7685	237741.01	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		8288.58	237,741.01	**lb/yr**
UNCONTROLLED TOTAL EMISSIONS (H_2S and Water)		0.946	27.14	**lb/hr**
		4.144	118.87	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Hydrogen Sulfide (TAP)	37.584	0.048

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Hydrogen Sulfide (TAP)	0.004	0.048	0.02

TANK TYPE: FIXED ROOF   Indiana Gasification

Unit ID: 023 D
DESCRIPTION: Slag Sump

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Slag	Slag	
SHELL COLOR		White	White	
ROOF TYPE		Flat	Flat	
INSIDE DIAMETER	CSA:	260	260	ft
TANK SHELL HEIGHT	Hs:	13	13	ft
MAX. TANK LIQUID VOLUME	Vlx:	3,380	3,380	cf
LIQUID HEIGHT	Hl:	6.5	6.5	ft
ROOF OUTAGE HEIGHT	Hro:	0.00	0.00	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	6.50	6.50	ft
VAPOR SPACE VOLUME	Vv:	1,690	1,690	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	37,492,800	221,488,628	gal/yr
ANNUAL THROUGHPUT	Q:	892,686	5,273,539	bbl/yr
TURNOVERS PER YEAR	N:	1482.70	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	18.05	18.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	647.7	671.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	596.8	671.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	601.9	676.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	591.7	666.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.6937	14.7002	psia
VAPOR PRESSURE AT Tlx	Pvx:	3.0707	16.2478	psia
VAPOR PRESSURE AT Tln	Pvn:	2.3570	13.2768	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.71	3.0	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.04)	(0.04)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.26	0.26	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	0.19	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0076	0.0368	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0720	PRESSURE VESSEL	
VENTED VAPOR SATURATION FACTOR	Ks:	0.52	0.16	
STANDING LOSS	Ls:	174.8158	0.00	lb/yr
WORKING LOSS	Lw:	8113.7685	237741.01	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		8288.58	237,741.01	lb/yr
UNCONTROLLED TOTAL EMISSIONS (H_2S and Water)		0.946	27.14	lb/hr
		4.144	118.87	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Hydrogen Sulfide (TAP)	37.584	0.048

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Hydrogen Sulfide (TAP)	0.004	0.048	0.02

TANK TYPE: FIXED ROOF

Indiana Gasification

Unit ID: 023 E
DESCRIPTION: Slag Sump

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Slag	Slag	
SHELL COLOR		White	White	
ROOF TYPE		Flat	Flat	
INSIDE DIAMETER	CSA:	260	260	ft
TANK SHELL HEIGHT	Hs:	13	13	ft
MAX. TANK LIQUID VOLUME	Vlx:	3,380	3,380	cf
LIQUID HEIGHT	Hl:	6.5	6.5	ft
ROOF OUTAGE HEIGHT	Hro:	0.00	0.00	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	6.50	6.50	ft
VAPOR SPACE VOLUME	Vv:	1,690	1,690	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	37,492,800	221,488,628	gal/yr
ANNUAL THROUGHPUT	Q:	892,686	5,273,539	bbl/yr
TURNOVERS PER YEAR	N:	1482.70	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	18.05	18.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	647.7	671.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	596.8	671.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	601.9	676.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	591.7	666.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.6937	14.7002	psia
VAPOR PRESSURE AT Tlx	Pvx:	3.0707	16.2478	psia
VAPOR PRESSURE AT Tln	Pvn:	2.3570	13.2768	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.71	3.0	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.04)	(0.04)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.26	0.26	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	0.19	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0076	0.0368	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0720	PRESSURE VESSEL	
VENTED VAPOR SATURATION FACTOR	Ks:	0.52	0.16	
STANDING LOSS	Ls:	174.8158	0.00	lb/yr
WORKING LOSS	Lw:	8113.7685	237741.01	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		8288.58	237,741.01	lb/yr
UNCONTROLLED TOTAL EMISSIONS (H_2S and Water)		0.946	27.14	lb/hr
		4.144	118.87	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Hydrogen Sulfide (TAP)	37.584	0.048

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Hydrogen Sulfide (TAP)	0.004	0.048	0.02

023
Raoult's Law Vapor Weight Fraction Determination
At Tla (596.8 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	612.0212	0.0065	0.0024	0.0819	0.0045
Water	1.0000	18.0150	0.0555	1.0000	2.6873	2.6872	0.9976	17.9717	0.9955
Total	1.0000	18.02	0.055509	1.0000		2.6937	1.0000	18.0536	1.0000

023
Raoult's Law Vapor Weight Fraction Determination
At Tlx (601.9 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	647.4126	0.0068	0.0022	0.0760	0.0042
Water	1.0000	18.0150	0.0555	1.0000	3.0638	3.0638	0.9978	17.9748	0.9958
Total	1.0000	18.02	0.055509	1.0000		3.0707	1.0000	18.0508	1.0000

023
Raoult's Law Vapor Weight Fraction Determination
At Tln (591.7 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	578.0600	0.0061	0.0026	0.0884	0.0049
Water	1.0000	18.0150	0.0555	1.0000	2.3509	2.3509	0.9974	17.9683	0.9951
Total	1.0000	18.02	0.055509	1.0000		2.3570	1.0000	18.0566	1.0000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

023
Raoult's Law Vapor Weight Fraction Determination
At Max Tla (671.7 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	1297.0643	0.0137	0.0009	0.0318	0.0018
Water	1.0000	18.0150	0.0555	1.0000	14.6867	14.6865	0.9991	17.9982	0.9982
Total	1.0000	18.02	0.055509	1.0000		14.7002	1.0000	18.0300	1.0000

023
Raoult's Law Vapor Weight Fraction Determination
At Max Tlx (676.8 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	1358.4245	0.0144	0.0009	0.0301	0.0017
Water	1.0000	18.0150	0.0555	1.0000	16.2336	16.2334	0.9991	17.9991	0.9983
Total	1.0000	18.02	0.055509	1.0000		16.2478	1.0000	18.0292	1.0000

023
Raoult's Law Vapor Weight Fraction Determination
At Max Tln (666.6 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Hydrogen Sulfide	2.0E-05	34.0759	5.9E-07	1.1E-05	1237.8070	0.0131	0.0010	0.0336	0.0019
Water	1.0000	18.0150	0.0555	1.0000	13.2639	13.2637	0.9990	17.9972	0.9981
Total	1.0000	18.02	0.055509	1.0000		13.2768	1.0000	18.0308	1.0000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 024

DESCRIPTION: Methanol De-Inventory Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Methanol	Methanol	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	55	55	ft
TANK SHELL HEIGHT	Hs:	40	40	ft
MAX. TANK LIQUID VOLUME	Vlx:	95,033	95,033	cf
LIQUID HEIGHT	Hl:	20	20	ft
ROOF OUTAGE HEIGHT	Hro:	3.77	3.77	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	23.77	23.77	ft
VAPOR SPACE VOLUME	Vv:	56,468	56,468	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	1,386,000	525,600,000	gal/yr
ANNUAL THROUGHPUT	Q:	33,000	12,514,286	bbl/yr
TURNOVERS PER YEAR	N:	1.95	739.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	32.04	32.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	527.7	559.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	529.6	559.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	534.7	564.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	524.5	554.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	1.9817	4.6184	psia
VAPOR PRESSURE AT Tlx	Pvx:	2.3055	5.2770	psia
VAPOR PRESSURE AT Tln	Pvn:	1.6976	4.0306	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.61	1.2	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.21	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0112	0.0246	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0635	0.131	
VENTED VAPOR SATURATION FACTOR	Ks:	0.29	0.15	
STANDING LOSS	Ls:	4181.9333	9780.23	lb/yr
WORKING LOSS	Lw:	2095.2688	383777.38	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		6277.20	393,557.60	lb/yr
UNCONTROLLED TOTAL EMISSIONS		0.717	44.93	lb/hr
		3.139	2.0E+02	TPY
VAPOR RECOVERY (CHILLER) EFFICIENCY		95	95	%

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.
ALTHOUGH TANK WILL ONLY CONTAIN METHANOL DURING THE TWO (2) RECTISOL DE-INVENTORYING PERIODS, STANDING LOSSES ARE CONSERVATIVELY ASSUMED TO OCCUR FOR 8,760 HR/YR.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Methanol (TAP)(VOC)	313.860	2.246

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Methanol (TAP)(VOC)	0.04	2.25	0.16

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 025

DESCRIPTION: Fresh Methanol Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Methanol	Methanol	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	42	42	ft
TANK SHELL HEIGHT	Hs:	33	33	ft
MAX. TANK LIQUID VOLUME	Vlx:	45,720	45,720	cf
LIQUID HEIGHT	Hl:	16.5	16.5	ft
ROOF OUTAGE HEIGHT	Hro:	2.88	2.88	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	19.38	19.38	ft
VAPOR SPACE VOLUME	Vv:	26,846	26,846	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	2,000,000	94,608,000	gal/yr
ANNUAL THROUGHPUT	Q:	47,619	2,252,571	bbl/yr
TURNOVERS PER YEAR	N:	5.85	276.6	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	32.04	32.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	527.7	559.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	529.6	559.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	534.7	564.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	524.5	554.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	1.9817	4.6184	psia
VAPOR PRESSURE AT Tlx	Pvx:	2.3055	5.2770	psia
VAPOR PRESSURE AT Tln	Pvn:	1.6976	4.0306	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.61	1.2	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.28	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0112	0.0246	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0635	0.131	
VENTED VAPOR SATURATION FACTOR	Ks:	0.33	0.17	
STANDING LOSS	Ls:	2290.2320	5519.80	lb/yr
WORKING LOSS	Lw:	3023.4760	91705.85	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		5313.71	97,225.65	lb/yr
UNCONTROLLED TOTAL EMISSIONS		0.607	11.10	lb/hr
		2.657	4.9E+01	TPY
VAPOR RECOVERY (CHILLER) EFFICIENCY		95	95	%

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

SPECIES	NORMAL SERVICE lb/yr	MAXIMUM HOURLY lb/hr
Methanol (TAP)(VOC)	265.685	0.555

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Methanol (TAP)(VOC)	0.03	0.55	0.13

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 026

DESCRIPTION: Sour Water Stripper Surge

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	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sour Water	Sour Water	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	36	36	ft
TANK SHELL HEIGHT	Hs:	24	24	ft
MAX. TANK LIQUID VOLUME	Vlx:	24,429	24,429	cf
LIQUID HEIGHT	Hl:	12	12	ft
ROOF OUTAGE HEIGHT	Hro:	2.47	2.47	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	14.47	14.47	ft
VAPOR SPACE VOLUME	Vv:	14,725	14,725	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	97,716	371,599,200	gal/yr
ANNUAL THROUGHPUT	Q:	2,327	8,847,600	bbl/yr
TURNOVERS PER YEAR	N:	4.00	2033.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	32.04	32.0	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	553.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	544.2	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	549.3	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	539.1	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	2.2732	7.4461	psia
VAPOR PRESSURE AT Tlx	Pvx:	2.4955	8.1523	psia
VAPOR PRESSURE AT Tln	Pvn:	2.0704	6.7986	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.43	1.4	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.18	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0125	0.0365	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0483	0.180	
VENTED VAPOR SATURATION FACTOR	Ks:	0.36	0.15	
STANDING LOSS	Ls:	1181.4897	5260.78	lb/yr
WORKING LOSS	Lw:	169.4526	382945.11	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		1350.94	388,205.89	lb/yr
UNCONTROLLED TOTAL EMISSIONS	(TAPs +water)	0.154	44.32	lb/hr
		0.675	194.10	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Ammonia (TAP)	55.121	1.660
Carbonyl Sulfide (TAP)(VOC)	7.623	0.192
Hydrogen Sulfide (TAP)	1071.701	26.739
Water	216.498	15.724
TOTAL (Including TAPs)	1350.942	44.316

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Ammonia (TAP)	0.006	1.660	0.028
Carbonyl Sulfide (TAP)(VOC)	0.00087	0.192	0.0038
Hydrogen Sulfide (TAP)	0.122	26.739	0.54
TOTAL	0.130	28.592	0.57

026
Raoult's Law Vapor Weight Fraction Determination
At Tla (544.2 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	164.5665	0.1573	0.0692	1.1787	0.0408
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	204.8233	0.0028	0.0012	0.1630	0.0056
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	323.5576	1.5289	0.6726	22.9180	0.7933
Water	0.9901	18.0150	0.0550	0.9943	0.5875	0.5842	0.2570	4.6297	0.1603
Total	1.0000	18.09	0.055275	1.0000		2.2732	1.0000	28.8895	1.0000

026
Raoult's Law Vapor Weight Fraction Determination
At Tlx (549.3 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	178.9567	0.1711	0.0686	1.1676	0.0408
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	219.1708	0.0030	0.0012	0.1589	0.0056
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	345.9243	1.6346	0.6550	22.3195	0.7803
Water	0.9901	18.0150	0.0550	0.9943	0.6908	0.6869	0.2752	4.9584	0.1733
Total	1.0000	18.09	0.055275	1.0000		2.4955	1.0000	28.6045	1.0000

026
Raoult's Law Vapor Weight Fraction Determination
At Tln (539.1 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	151.0775	0.1444	0.0698	1.1881	0.0407
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	191.1775	0.0026	0.0013	0.1671	0.0057
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	302.2601	1.4282	0.6898	23.5063	0.8058
Water	0.9901	18.0150	0.0550	0.9943	0.4980	0.4951	0.2391	4.3083	0.1477
Total	1.0000	18.09	0.055275	1.0000		2.0704	1.0000	29.1697	1.0000

<u>Calculations:</u>

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

026
Raoult's Law Vapor Weight Fraction Determination
At Max Tla (609.7 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	432.2444	0.4133	0.0555	0.9452	0.0375
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	450.8631	0.0062	0.0008	0.1095	0.0043
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	704.0007	3.3265	0.4467	15.2232	0.6034
Water	0.9901	18.0150	0.0550	0.9943	3.7214	3.7002	0.4969	8.9521	0.3548
Total	1.0000	18.09	0.055275	1.0000		7.4461	1.0000	25.2301	1.0000

026
Raoult's Law Vapor Weight Fraction Determination
At Max Tlx (614.8 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	461.9098	0.4416	0.0542	0.9226	0.0369
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	476.4069	0.0065	0.0008	0.1057	0.0042
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	743.1684	3.5116	0.4308	14.6782	0.5878
Water	0.9901	18.0150	0.0550	0.9943	4.2165	4.1925	0.5143	9.2647	0.3710
Total	1.0000	18.09	0.055275	1.0000		8.1523	1.0000	24.9712	1.0000

026
Raoult's Law Vapor Weight Fraction Determination
At Max Tln (604.6 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.0009	17.0299	5.3E-05	0.0010	404.0334	0.3863	0.0568	0.9676	0.0380
Carbonyl Sulfide	0.0001	132.1599	7.6E-07	1.4E-05	426.3513	0.0058	0.0009	0.1135	0.0045
Hydrogen Sulfide	0.0089	34.0759	0.0003	0.0047	666.3631	3.1487	0.4631	15.7818	0.6190
Water	0.9901	18.0150	0.0550	0.9943	3.2764	3.2578	0.4792	8.6325	0.3386
Total	1.0000	18.09	0.055275	1.0000		6.7986	1.0000	25.4954	1.0000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 027 A

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF

Indiana Gasification

Unit ID: 027 B

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 027 C

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 027 D

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 027 E

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF   Indiana Gasification   Unit ID: 027 F

DESCRIPTION: Sulfuric Acid Storage Tank

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Sulfuric Acid	Sulfuric Acid	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	50	50	ft
TANK SHELL HEIGHT	Hs:	60	60	ft
MAX. TANK LIQUID VOLUME	Vlx:	117,810	117,810	cf
LIQUID HEIGHT	Hl:	30	30	ft
ROOF OUTAGE HEIGHT	Hro:	3.43	3.43	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	33.43	33.43	ft
VAPOR SPACE VOLUME	Vv:	65,630	65,630	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	13,665,600	814,680,000	gal/yr
ANNUAL THROUGHPUT	Q:	325,371	19,397,143	bbl/yr
TURNOVERS PER YEAR	N:	15.50	924.3	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	98.07	98.1	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	564.7	609.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	550.3	609.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	555.4	614.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	545.2	604.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	0.0000130	0.000270	psia
VAPOR PRESSURE AT Tlx	Pvx:	0.0000175	0.000339	psia
VAPOR PRESSURE AT Tln	Pvn:	0.0000096	0.000215	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	0.0000079	0.000124	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.20	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.000000216	0.00000405	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.0173	0.014	
VENTED VAPOR SATURATION FACTOR	Ks:	1.00	1.00	
STANDING LOSS	Ls:	0.0898	1.33	lb/yr
WORKING LOSS	Lw:	0.4158	102.43	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		0.51	103.77	lb/yr
UNCONTROLLED TOTAL EMISSIONS		5.8E-05	1.2E-02	lb/hr
		2.5E-04	5.2E-02	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Sulfuric Acid (TAP)	0.506	0.012

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Sulfuric Acid (TAP)	5.8E-05	1.2E-02	2.5E-04

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 028 A
DESCRIPTION: Aqueous Ammonia

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Ammonia	Ammonia	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	14	14	ft
TANK SHELL HEIGHT	Hs:	28	28	ft
MAX. TANK LIQUID VOLUME	Vlx:	4,310	4,310	cf
LIQUID HEIGHT	Hl:	14	14	ft
ROOF OUTAGE HEIGHT	Hro:	0.96	0.96	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	14.96	14.96	ft
VAPOR SPACE VOLUME	Vv:	2,303	2,303	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	440,000	105,120,000	gal/yr
ANNUAL THROUGHPUT	Q:	10,476	2,502,857	bbl/yr
TURNOVERS PER YEAR	N:	13.64	3259.9	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	17.03	17.03	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	539.7	566.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	536.3	566.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	541.4	571.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	531.2	561.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	5.3792	10.8983	psia
VAPOR PRESSURE AT Tlx	Pvx:	6.0783	12.1607	psia
VAPOR PRESSURE AT Tln	Pvn:	4.7256	9.7276	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	1.35	2.4	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.18	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0159	0.0305	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.1520	0.600	
VENTED VAPOR SATURATION FACTOR	Ks:	0.19	0.10	
STANDING LOSS	Ls:	386.3219	1595.82	lb/yr
WORKING LOSS	Lw:	959.6994	81695.32	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		1346.02	83,291.14	lb/yr
UNCONTROLLED TOTAL EMISSIONS (Ammonia and Water)		0.154	9.51	lb/hr
		0.673	41.65	TPY
SCRUBBER EFFICIENCY		60	60	%

SPECIATED EMISSIONS:

SPECIES	NORMAL SERVICE lb/yr	MAXIMUM HOURLY lb/hr
Ammonia (TAP)	500.215	3.461

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Ammonia (TAP)	0.057	3.461	0.25

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 028 B
DESCRIPTION: Aqueous Ammonia

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Ammonia	Ammonia	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	14	14	ft
TANK SHELL HEIGHT	Hs:	28	28	ft
MAX. TANK LIQUID VOLUME	Vlx:	4,310	4,310	cf
LIQUID HEIGHT	Hl:	14	14	ft
ROOF OUTAGE HEIGHT	Hro:	0.96	0.96	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	14.96	14.96	ft
VAPOR SPACE VOLUME	Vv:	2,303	2,303	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	440,000	105,120,000	gal/yr
ANNUAL THROUGHPUT	Q:	10,476	2,502,857	bbl/yr
TURNOVERS PER YEAR	N:	13.64	3259.9	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	17.03	17.03	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	539.7	566.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	536.3	566.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	541.4	571.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	531.2	561.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	5.3792	10.8983	psia
VAPOR PRESSURE AT Tlx	Pvx:	6.0783	12.1607	psia
VAPOR PRESSURE AT Tln	Pvn:	4.7256	9.7276	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	1.35	2.4	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.18	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0159	0.0305	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.1520	0.600	
VENTED VAPOR SATURATION FACTOR	Ks:	0.19	0.10	
STANDING LOSS	Ls:	386.3219	1595.82	lb/yr
WORKING LOSS	Lw:	959.6994	81695.32	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		1346.02	83,291.14	lb/yr
UNCONTROLLED TOTAL EMISSIONS (Ammonia and Water)		0.154	9.51	lb/hr
		0.673	41.65	TPY
SCRUBBER EFFICIENCY		60	60	%

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Ammonia (TAP)	500.215	3.461

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Ammonia (TAP)	0.057	3.461	0.25

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Tla (536.3 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		5.0171	0.9327	15.8835	0.9291
Water	0.8050	18.0150	0.0447	0.7960	0.4549	0.3621	0.0673	1.2128	0.0709
Total	1.0000	17.81	0.056135	1.0000		5.3792	1.0000	17.0962	1.0000

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Tlx (541.4 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		5.6502	0.9296	15.8305	0.9258
Water	0.8050	18.0150	0.0447	0.7960	0.5378	0.4281	0.0704	1.2688	0.0742
Total	1.0000	17.81	0.056135	1.0000		6.0783	1.0000	17.0993	1.0000

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Tln (531.2 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		4.4204	0.9354	15.9300	0.9319
Water	0.8050	18.0150	0.0447	0.7960	0.3834	0.3052	0.0646	1.1635	0.0681
Total	1.0000	17.81	0.056135	1.0000		4.7256	1.0000	17.0935	1.0000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Max Tla (566.7 °R)

Species	A Liquid Weight Fraction	B Liquid Molecular Weight	C Liquid Lb-Moles	D Liquid Mole Fraction	E Vapor Pressure psia	F Partial Pressure psia	G Vapor Mole Fraction	H G x B	I Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		9.9668	0.9145	15.5743	0.9100
Water	0.8050	18.0150	0.0447	0.7960	1.1702	0.9315	0.0855	1.5398	0.0900
Total	1.0000	17.81	0.056135	1.0000		10.8983	1.0000	17.1141	1.0000

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Max Tlx (571.8 °R)

Species	A Liquid Weight Fraction	B Liquid Molecular Weight	C Liquid Lb-Moles	D Liquid Mole Fraction	E Vapor Pressure psia	F Partial Pressure psia	G Vapor Mole Fraction	H G x B	I Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		11.0810	0.9112	15.5179	0.9066
Water	0.8050	18.0150	0.0447	0.7960	1.3563	1.0797	0.0888	1.5995	0.0934
Total	1.0000	17.81	0.056135	1.0000		12.1607	1.0000	17.1174	1.0000

028 A&B
Raoult's Law Vapor Weight Fraction Determination
At Max Tln (561.6 °R)

Species	A Liquid Weight Fraction	B Liquid Molecular Weight	C Liquid Lb-Moles	D Liquid Mole Fraction	E Vapor Pressure psia	F Partial Pressure psia	G Vapor Mole Fraction	H G x B	I Vapor Weight Fraction
Ammonia	0.1950	17.0299	0.0115	0.2040		8.9264	0.9176	15.6273	0.9133
Water	0.8050	18.0150	0.0447	0.7960	1.0065	0.8012	0.0824	1.4838	0.0867
Total	1.0000	17.81	0.056135	1.0000		9.7276	1.0000	17.1110	1.0000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 029

DESCRIPTION: Diesel

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Diesel	Diesel	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	11	11	ft
TANK SHELL HEIGHT	Hs:	14	14	ft
MAX. TANK LIQUID VOLUME	Vlx:	1,330	1,330	cf
LIQUID HEIGHT	Hl:	7	7	ft
ROOF OUTAGE HEIGHT	Hro:	0.75	0.75	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	7.75	7.75	ft
VAPOR SPACE VOLUME	Vv:	737	737	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	10,000	87,184,247	gal/yr
ANNUAL THROUGHPUT	Q:	238	2,075,815	bbl/yr
TURNOVERS PER YEAR	N:	1.00	8759.1	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	63.83	63.5	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	539.7	566.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	536.3	566.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	541.4	571.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	531.2	561.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	6.0453	10.5614	psia
VAPOR PRESSURE AT Tlx	Pvx:	6.8042	11.4923	psia
VAPOR PRESSURE AT Tln	Pvn:	5.6843	9.6891	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	1.12	1.8	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.22)	(0.22)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.44	0.44	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0670	0.1103	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.1166	0.365	
VENTED VAPOR SATURATION FACTOR	Ks:	0.29	0.19	
STANDING LOSS	Ls:	603.3699	2029.83	lb/yr
WORKING LOSS	Lw:	91.8799	236835.26	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		695.25	238,865.09	lb/yr
UNCONTROLLED TOTAL EMISSIONS		0.0794	27.27	lb/hr
		0.3476	119.43	TPY

COMMENTS:
EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

EMISSIONS:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
anthracene	2.9E-07	1.9E-04	1.3E-06
benzene	1.1E-03	0.28	4.7E-03
Biphenyl	3.2E-06	1.8E-03	1.4E-05
ethyl benzene	5.4E-03	1.74	0.02
naphthalene	2.1E-04	0.10	9.0E-04
Toluene	3.2E-03	0.93	0.01
Xylene	6.8E-03	2.23	0.03
non-TAP VOC	0.06	21.97	0.27
Total	0.08	27.27	0.35

TANK TYPE: FIXED ROOF Indiana Gasification

Unit ID: 030

DESCRIPTION: Gasoline

	AP-42 VARIABLE	ANNUAL THROUGHPUT CASE (lb/hr avg)	MAXIMUM HOURLY CASE (lb/hr max)	UNITS
TANK CHARACTERISTICS		Gasoline	Gasoline	
SHELL COLOR		White	White	
ROOF TYPE		Dome	Dome	
INSIDE DIAMETER	D:	5	5	ft
TANK SHELL HEIGHT	Hs:	8	8	ft
MAX. TANK LIQUID VOLUME	Vlx:	157	157	cf
LIQUID HEIGHT	Hl:	4	4	ft
ROOF OUTAGE HEIGHT	Hro:	0.34	0.34	ft
VAPOR SPACE OUTAGE HEIGHT	Hvo:	4.34	4.34	ft
VAPOR SPACE VOLUME	Vv:	85	85	cf
AMBIENT CONDITIONS				
AVERAGE ATMOSPHERIC PRESSURE	Pa:	14.7	14.7	psia
DAILY MAX AMBIENT TEMPERATURE	Tax:	77.6	77.6	°F
DAILY MIN AMBIENT TEMPERATURE	Tan:	58.3	58.3	°F
AMBIENT TEMPERATURE	Taa:	527.95	527.95	R
DAILY SOLAR INSULATION FACTOR	I:	1365	1365	Btu/sf day
BULK LIQUID CHARACTERISTICS				
ANNUAL THROUGHPUT	An:	8,000	5,256,000	gal/yr
ANNUAL THROUGHPUT	Q:	190	125,143	bbl/yr
TURNOVERS PER YEAR	N:	6.81	4472.6	turn/year
VAPOR MOLECULAR WEIGHT	Mv:	66.12	66.3	lb/lbmol
TEMPERATURE PARAMETERS				
LIQUID BULK TEMPERATURE	Tb:	539.7	566.7	R
DAILY AVG LIQ. SURFACE TEMP.	Tla:	536.3	566.7	R
MAX DAILY AVG LIQ. SURFACE TEMP.	Tlx:	541.4	571.8	R
MIN DAILY AVG LIQ. SURFACE TEMP.	Tln:	531.2	561.6	R
DAILY AMBIENT TEMPERATURE RANGE	ΔTa:	19.3	19.3	R
DAILY VAPOR TEMPERATURE RANGE	ΔTv:	20.4	20.4	R
VAPOR PRESSURE PARAMETERS				
VAPOR PRESSURE AT Tla	Pva:	6.2000	10.8800	psia
VAPOR PRESSURE AT Tlx	Pvx:	6.9800	11.8490	psia
VAPOR PRESSURE AT Tln	Pvn:	5.8200	9.9730	psia
DAILY VAPOR PRESSURE RANGE	ΔPv:	1.16	1.9	psia
BREATHER VENT PRESSURE SETTING	Pbp:	0.22	0.22	psia
BREATHER VENT VACUUM PRESSURE SETTING	Pbv:	(0.07)	(0.07)	psia
BREATHER VENT PRESSURE SETTING RANGE	ΔPb:	0.29	0.29	psia
FACTORS				
PAINT FACTOR	α:	0.17	0.17	
TURNOVER FACTOR	Kn:	1.00	0.17	
WORKING LOSS PRODUCT FACTOR	Kp:	1.0	1.0	
CALCULATED FACTORS				
VAPOR DENSITY	Wv:	0.0712	0.1186	lb/cf
VAPOR EXPANSION FACTOR	Ke:	0.1404	0.451	
VENTED VAPOR SATURATION FACTOR	Ks:	0.41	0.29	
STANDING LOSS	Ls:	128.2145	475.15	lb/yr
WORKING LOSS	Lw:	78.0852	15644.55	lb/yr
OPERATING HOURS PER YEAR		8760	8760	hr/yr
ANNUAL EMISSIONS		206.30	16,119.71	lb/yr
UNCONTROLLED TOTAL EMISSIONS		0.024	1.84	lb/hr
		0.103	8.06	TPY

COMMENTS:

EMISSIONS CALCULATED PER AP-42, CHAPTER 7 (9/97), AND URS TANK METHODOLOGY.

SPECIATED EMISSIONS:

	NORMAL SERVICE	MAXIMUM HOURLY
SPECIES	lb/yr	lb/hr
Benzene	0.49	0.005
Cumene	0.04	0.001
Ethylbenzene	0.18	0.002
n-Hexane	4.75	0.048
Toluene	1.22	0.014
Xylene	0.37	0.005
non-TAP VOC	199.24	1.766
TOTAL (Including TAPs)	206.300	1.840

EMISSIONS TO BE PERMITTED:

SPECIES	lb/hr (avg)	lb/hr (max)	TPY
Benzene (TAP)(VOC)	5.6E-05	0.01	2.5E-04
Cumene (TAP)(VOC)	4.6E-06	5.5E-04	2.0E-05
Ethylbenzene (TAP)(VOC)	2.1E-05	2.3E-03	9.1E-05
n-Hexane (TAP)(VOC)	5.4E-04	0.05	2.4E-03
Toluene (TAP)(VOC)	1.4E-04	0.01	6.1E-04
Xylene (TAP)(VOC)	4.3E-05	4.7E-03	1.9E-04
non-TAP VOC	0.02	1.77	0.10
Total TAP VOC	0.02	1.84	0.10

ALL LB/HR AND TPY LESS THAN 0.01 AND GREATER THAN ZERO WILL BE REPRESENTED AS "< 0.01" ON THE EIQ AND AAE FORMS.

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Tla (535.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#NAME?	#NAME?	#NAME?	#VALUE!	#NAME?	#NAME?	#NAME?	#NAME?
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.0050	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.0100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.0010	92.14	1.1E-05	#NAME?	0.5201	#NAME?	#NAME?	#NAME?	#NAME?
Xylene	0.0070	318.50	2.2E-05	#NAME?	0.1587	#NAME?	#NAME?	#NAME?	#NAME?
non-TAP VOC	0.9734	142.11	0.0068	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?
Total	1.0000	#NAME?	#NAME?	#NAME?		0.0130	#NAME?	#NAME?	#NAME?

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Tlx (540.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.0050	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.0100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.0010	92.14	1.1E-05	#N/A	0.6002	#N/A	#N/A	#N/A	#N/A
Xylene	0.0070	318.50	2.2E-05	#N/A	0.1864	#N/A	#N/A	#N/A	#N/A
non-TAP VOC	0.9734	142.11	0.0068	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total	1.0000	#N/A	#N/A	#N/A		0.0150	#N/A	#N/A	#N/A

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Tln (525.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.00500	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.01000	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.00100	92.14	1.1E-05	#N/A	3.9E-01	#N/A	#N/A	#N/A	#N/A
Xylene	0.00700	318.50	2.2E-05	#N/A	1.1E-01	#N/A	#N/A	#N/A	#N/A
non-TAP VOC	0.9734	142.11	0.0068	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total	1.0000	#N/A	#N/A	#N/A		0.0098	#N/A	#N/A	#N/A

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Max Tla (570.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.00500	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.01000	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.00100	92.14	1.1E-05	#N/A	1.3E+00	#N/A	#N/A	#N/A	#N/A
Xylene	0.00700	318.50	2.2E-05	#N/A	4.5E-01	#N/A	#N/A	#N/A	#N/A
non-TAP VOC	0.9734	142.11	0.0068	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total	1.0000	#N/A	#N/A	#N/A		0.0390	#N/A	#N/A	#N/A

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Max Tlx (575.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.00500	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.01000	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.00100	92.14	1.1E-05	#N/A	1.5E+00	#N/A	#N/A	#N/A	#N/A
Xylene	0.00700	318.50	2.2E-05	#N/A	5.2E-01	#N/A	#N/A	#N/A	#N/A
non-TAP VOC	0.9734	142.11	0.0068	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total	1.0000	#N/A	#N/A	#N/A		0.0450	#N/A	#N/A	#N/A

Raoult's Law Vapor Weight Fraction Determination
Heavy Fuels
At Max Tln (560.0 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
anthracene	0.00250	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
benzene	0.00010	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Biphenyl	0.00100	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
ethyl benzene	0.00500	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
naphthalene	0.01000	#N/A	#N/A	#N/A	#VALUE!	#N/A	#N/A	#N/A	#N/A
Toluene	0.00100	92.1409	1.1E-05	#N/A	1.03231	#N/A	#N/A	#N/A	#N/A
Xylene	0.00700	318.5010	2.2E-05	#N/A	0.34201	#N/A	#N/A	#N/A	#N/A
non-TAP VOC	0.9734	142.11	0.00685	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total	1.0000	#N/A	#N/A	#N/A		0.0290	#N/A	#N/A	#N/A

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Raoult's Law Vapor Weight Fraction Determination

At Tla (536.3 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.5E-05	0.0069	1.8181	0.0125	0.0020	0.1570	0.0024
Cumene	0.0128	120.19	1.1E-04	0.0077	0.0873	0.0007	0.0001	0.0130	0.0002
Ethylbenzene	0.0271	106.17	2.6E-04	0.0185	0.1835	0.0034	0.0005	0.0580	0.0009
n-Hexane	0.0452	86.18	5.2E-04	0.0380	2.8843	0.1095	0.0177	1.5217	0.0230
Toluene	0.0614	92.14	6.7E-04	0.0482	0.5466	0.0264	0.0043	0.3917	0.0059
Xylene	0.0618	318.50	1.9E-04	0.0140	0.1658	0.0023	0.0004	0.1196	0.0018
non-TAP VOC	0.7843	65.48	0.0120	0.8667	6.9747	6.0453	0.9750	63.8494	0.9658
Total	1.0000	72.37	0.013819	1.0000		6.2000	1.0000	66.1105	1.0000

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Raoult's Law Vapor Weight Fraction Determination

At Tlx (541.4 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.47E-05	0.0069	2.0697	1.4E-02	0.00203	0.15879	0.00240
Cumene	0.0128	120.19	1.06E-04	0.0077	0.1038	8.0E-04	0.00011	0.01378	0.00021
Ethylbenzene	0.0271	106.17	2.55E-04	0.0185	0.2155	4.0E-03	0.00057	0.06054	0.00092
n-Hexane	0.0452	86.18	5.24E-04	0.0380	3.2576	1.2E-01	0.01771	1.52656	0.02309
Toluene	0.0614	92.14	6.66E-04	0.0482	0.6315	3.0E-02	0.00436	0.40198	0.00608
Xylene	0.0618	318.50	1.94E-04	0.0140	0.1951	2.7E-03	0.00039	0.12499	0.00189
non-TAP VOC	0.7843	65.48	1.20E-02	0.8667	7.8503	6.8042	0.97481	63.83389	0.96542
Total	1.0000	72.37	0.013819	1.0000		6.98000	1.0000	66.1205	1.0000

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Raoult's Law Vapor Weight Fraction Determination

At Tln (531.2 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.47E-05	0.00686	1.5924	1.1E-02	0.00188	0.14652	0.00222
Cumene	0.0128	120.19	1.06E-04	0.00771	0.0731	5.6E-04	0.00010	0.01164	0.00018
Ethylbenzene	0.0271	106.17	2.55E-04	0.01847	0.1556	2.9E-03	0.00049	0.05245	0.00079
n-Hexane	0.0452	86.18	5.24E-04	0.03796	2.5466	9.7E-02	0.01661	1.43127	0.02166
Toluene	0.0614	92.14	6.66E-04	0.04822	0.4716	2.3E-02	0.00391	0.36008	0.00545
Xylene	0.0618	318.50	1.94E-04	0.01404	0.1403	2.0E-03	0.00034	0.10784	0.00163
non-TAP VOC	0.7843	65.48	1.20E-02	0.86674	6.5582	5.6843	0.97668	63.95605	0.96807
Total	1.0000	72.37	0.013819	1.0000		5.82000	1.0000	66.0658	1.0000

<u>Calculations:</u>

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

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Raoult's Law Vapor Weight Fraction Determination
At Max Tla (566.7 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.5E-05	0.0069	3.7724	2.6E-02	0.00238	0.18568	0.00280
Cumene	0.0128	120.19	1.1E-04	0.0077	0.2313	1.8E-03	0.00016	0.01969	0.00030
Ethylbenzene	0.0271	106.17	2.6E-04	0.0185	0.4536	8.4E-03	0.00077	0.08177	0.00123
n-Hexane	0.0452	86.18	5.2E-04	0.0380	5.7257	2.2E-01	0.01997	1.72137	0.02598
Toluene	0.0614	92.14	6.7E-04	0.0482	1.2331	5.9E-02	0.00547	0.50358	0.00760
Xylene	0.0618	318.50	1.9E-04	0.0140	0.4139	5.8E-03	0.00053	0.17014	0.00257
non-TAP VOC	0.7843	65.48	1.2E-02	0.8667	12.1851	10.5614	0.97071	63.56551	0.95951
Total	1.0000	72.37	0.013819	1.0000		10.8800	1.0000	66.2477	1.0000

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Raoult's Law Vapor Weight Fraction Determination
At Max Tlx (571.8 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.5E-05	0.0069	4.2264	2.9E-02	0.00245	0.19101	0.00288
Cumene	0.0128	120.19	1.1E-04	0.0077	0.2692	2.1E-03	0.00018	0.02104	0.00032
Ethylbenzene	0.0271	106.17	2.6E-04	0.0185	0.5223	9.6E-03	0.00081	0.08645	0.00130
n-Hexane	0.0452	86.18	5.2E-04	0.0380	6.3712	2.4E-01	0.02041	1.75881	0.02654
Toluene	0.0614	92.14	6.7E-04	0.0482	1.3999	6.8E-02	0.00570	0.52494	0.00792
Xylene	0.0618	318.50	1.9E-04	0.0140	0.4772	6.7E-03	0.00057	0.18010	0.00272
non-TAP VOC	0.7843	65.48	1.2E-02	0.8667	13.2591	11.4923	0.96989	63.51174	0.95832
Total	1.0000	72.37	0.013819	1.0000		11.84900	1.0000	66.274	1.0000

30
Raoult's Law Vapor Weight Fraction Determination
At Max Tln (561.6 °R)

	A	B	C	D	E	F	G	H	I
Species	Liquid Weight Fraction	Liquid Molecular Weight	Liquid Lb-Moles	Liquid Mole Fraction	Vapor Pressure psia	Partial Pressure psia	Vapor Mole Fraction	G x B	Vapor Weight Fraction
Benzene	0.0074	78.11	9.5E-05	0.0069	3.3588	2.3E-02	0.00231	0.18035	0.00272
Cumene	0.0128	120.19	1.1E-04	0.0077	0.1981	1.5E-03	0.00015	0.01840	0.00028
Ethylbenzene	0.0271	106.17	2.6E-04	0.0185	0.3928	7.3E-03	0.00073	0.07724	0.00117
n-Hexane	0.0452	86.18	5.2E-04	0.0380	5.1337	1.9E-01	0.01954	1.68376	0.02543
Toluene	0.0614	92.14	6.7E-04	0.0482	1.0832	5.2E-02	0.00524	0.48262	0.00729
Xylene	0.0618	318.50	1.9E-04	0.0140	0.3579	5.0E-03	0.00050	0.16051	0.00242
non-TAP VOC	0.7843	65.48	1.2E-02	0.8667	11.1787	9.6891	0.97153	63.61893	0.96069
Total	1.0000	72.37	0.013819	1.0000		9.97300	1.00000	66.2218	1.00000

Calculations:

A = Liquid weight fraction
B = Liquid molecular weight
C = A / B (liquid Lb-moles)
D = C / ΣC (liquid mole fraction)
E = Pure component vapor pressure
F = D x E (partial pressure)
G = F / ΣF (vapor mole fraction)
H = G x B (vapor molecular weight fraction)
I = H / ΣH (vapor weight fraction)

CHEMICAL NAME	CAS NUMBER	MOLECULAR WEIGHT	RIEDEL CONSTANTS				
			A	B	C	D	E
Ammonia	7664-41-7	17.03	90.483	4669.7	-11.607	0.017194	1
Carbon Dioxide	124-38-9	44.01	140.54	4735	-21.268	0.040909	1
Carbon Monoxide	630-08-0	28.01	45.698	1076.6	-4.8814	7.567E-05	2
Benzene	71-43-2	78.11	83.107	6486.2	-9.2194	6.984E-06	2
Cumene	98-82-8	120.19	102.81	8674.6	-11.922	7.005E-06	2
Ethylbenzene	100-41-4	106.17	89.063	7733.7	-9.917	5.986E-06	2
Toluene	108-88-3	92.14	76.945	6729.8	-8.179	5.302E-06	2
Carbonyl Sulfide	463-58-1	132.16	89.756	3957.4	-12.036	0.020634	1
Hydrogen Sulfide	7783-06-4	34.08	85.584	3839.9	-11.199	0.018848	1
Methanol	67-56-1	32.04	82.718	6904.5	-8.8622	7.47E-06	2
Glycol	112-27-6	150.17	152.480	16449.0	-17.6700	6.45E-18	6
Water	7732-18-5	18.01	73.649	7258.2	-7.3037	4.165E-06	2
Vinyl Acetate	108-05-4	86.09	57.406	5702.8	-5.0307	1.10E-17	6

Comments:
Riedel Equation & Constants are from UCC's Database

Riedel Equation:
ln(P)=A-B/T+Cln(T)+DT^E
P is in PA
T is Temperature in degrees Kelvin

Note:
For VPRiedel() Function; Use Rankin as second variable. The function will convert Rankin into Kelvin.
Example:
VPRiedel("Methanol",527.4)
Or
VPRiedel(A12,J1)
Where A12 is the Chemical and J1 is the Temperature in Rankin

PW32 Reidel	ln(P)=A-B/T+Cln(T)+DT^E

Used the decene constants for alkene.
Used the triethylene glycol constants for polyethylene glycol.

ANTOINES CONSTANTS FOR VARIOUS COMPONENTS

CHEMICAL NAME	**CAS** NUMBER	**MOLECULAR WEIGHT**	**ANTOINE CONSTANTS** A	B	C	**VP@20°C (mmHg)**
TOLUENE	108-88-3	92.14	6.9866	1363.4762	221.4790	21.88991
n-hexane	110-54-3	86.18	6.8702	1168.7199	224.2099	121.47341
Xylene	1330-20-7	318.50	6.99052	1453.43	215.307	6.51299
Sulfuric Acid	7664-93-9	98.07	7.3456	2421.1499	197.798	0.00017

Notes:

Antoines Equation: Log10(P) = A - (B / (T +C)) P as mmHg; T as °C

Antoines Constants from the UCC's Chemical database.

Glycol Ethers (II): Methyl Cellosolve

Glycol Ethers (II-S): Methyl Carbitol (Glycol Ethers (II-S) vapor pressure will be utilized for all glycol ethers Supl. List (table 51.3).

STORAGE TANK PARAMETERS

TANK IDENTIFICATION		TANK CHARACTERISTICS							BULK LIQUID CHARACTERI	
Unit ID	Tank ID	Tank Common Name	Shell Color	Paint Condition	Roof Type	Bottom Type	Inside Diameter	Tank Shell Height	Annual Thruput	Annual Throughput
							(ft)	(ft)	lb/yr	Gal/yr
023 A		Slag Sump	White	Good	Flat	Flat	260	13	400,048,176	37,492,800
023 B		Slag Sump	White	Good	Flat	Flat	260	13	400,048,176	37,492,800
023 C		Slag Sump	White	Good	Flat	Flat	260	13	400,048,176	37,492,800
023 D		Slag Sump	White	Good	Flat	Flat	260	13	400,048,176	37,492,800
023 E		Slag Sump	White	Good	Flat	Flat	260	13	400,048,176	37,492,800
024		Methanol De-Inventory Tank	White	Good	Dome	flat	55	40	9,203,040	1,386,000
025		Fresh Methanol Storage Tank	White	Good	Dome	flat	42	33	13,280,000	2,000,000
027 A		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
027 B		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
027 C		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
027 D		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
027 E		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
027 F		Sulfuric Acid Storage Tank	White	Good	Dome	flat	50	60	206,350,560	13,665,600
028 A		Aqueous Ammonia	White	Good	Dome	flat	14	28	3,388,000	440,000
028 B		Aqueous Ammonia	White	Good	Dome	flat	14	28	3,388,000	440,000
029		Diesel	White	Good	Dome	flat	11	14	71,000	10,000
030		Gasoline	White	Good	Dome	flat	5	8	48,800	8,000
026		Sour Water Stripper Surge	White	Good	Dome	flat	36	24	0	0

TANK IDENTIFICATION		ISTICS		BULK LIQUID CHARACTERISTICS					
Unit ID	Tank ID	Tank Common Name	Max Pump Rate	Horiz/ Vert	Vapor Molecular Weight	Max Vapor Molecular Weight	Ts (°F)	Max Ts (°F)	Ts (°C)
			Gal/hr		(Mv)	(Mv)			
023 A		Slag Sump	33,540	Vertical	18.0536	18.0300			
023 B		Slag Sump	33,540	Vertical	18.0536	18.0300			
023 C		Slag Sump	33,540	Vertical	18.0536	18.0300			
023 D		Slag Sump	33,540	Vertical	18.0536	18.0300			
023 E		Slag Sump	33,540	Vertical	18.0536	18.0300			
024		Methanol De-Inventory Tank	60,000	Vertical	32.0399	32.0399			
025		Fresh Methanol Storage Tank	10,800	Vertical	32.0399	32.0399			
027 A		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
027 B		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
027 C		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
027 D		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
027 E		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
027 F		Sulfuric Acid Storage Tank	93,000	Vertical	98.0700	98.0700			
028 A		Aqueous Ammonia	12,000	Vertical	17.0299	17.0299			
028 B		Aqueous Ammonia	12,000	Vertical	17.0299	17.0299			
029		Diesel	6,000	Vertical	63.8339	63.5117			
030		Gasoline	600	Vertical	66.1205	66.2741			
026		Sour Water Stripper Surge	42,420	Vertical	32.0399	32.0399			

STORAGE TANK PARAMETERS

TANK IDENTIFICATION		TEMPERATURES						
Unit ID	Tank ID	Tank Common Name	Max Ts (°C)	Liquid Bulk Temperature	Maximum Liquid Bulk Temperature	Tla	Tlx	Tln
				(R)	(R)			
023 A		Slag Sump		648	672			
023 B		Slag Sump		648	672			
023 C		Slag Sump		648	672			
023 D		Slag Sump		648	672			
023 E		Slag Sump		648	672			
024		Methanol De-Inventory Tank		528	560			
025		Fresh Methanol Storage Tank		528	560			
027 A		Sulfuric Acid Storage Tank		565	610			
027 B		Sulfuric Acid Storage Tank		565	610			
027 C		Sulfuric Acid Storage Tank		565	610			
027 D		Sulfuric Acid Storage Tank		565	610			
027 E		Sulfuric Acid Storage Tank		565	610			
027 F		Sulfuric Acid Storage Tank		565	610			
028 A		Aqueous Ammonia		540	567			
028 B		Aqueous Ammonia		540	567			
029		Diesel		540	567			
030		Gasoline		540	567			
026		Sour Water Stripper Surge		554	610			

TANK IDENTIFICATION			VAPOR PRE		
Unit ID	Tank ID	Tank Common Name	Pva	Pvx	Pvn
023 A		Slag Sump	2.6937	3.0707	2.3570
023 B		Slag Sump	2.6937	3.0707	2.3570
023 C		Slag Sump	2.6937	3.0707	2.3570
023 D		Slag Sump	2.6937	3.0707	2.3570
023 E		Slag Sump	2.6937	3.0707	2.3570
024		Methanol De-Inventory Tank	1.9817	2.3055	1.6976
025		Fresh Methanol Storage Tank	1.9817	2.3055	1.6976
027 A		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
027 B		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
027 C		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
027 D		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
027 E		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
027 F		Sulfuric Acid Storage Tank	0.00001	0.00002	0.00001
028 A		Aqueous Ammonia	5.37923	6.07829	4.72561
028 B		Aqueous Ammonia	5.37923	6.07829	4.72561
029		Diesel	6.04531	6.80420	5.68427
030		Gasoline	6.20000	6.98000	5.82000
026		Sour Water Stripper Surge	2.2732	2.4955	2.0704

STORAGE TANK PARAMETERS

TANK IDENTIFICATION		SSURE PARAMETERS							
Unit ID	Tank ID	Tank Common Name	Max Pva	Max Pvx	Max Pvn	Breather Vent Pressure Setting (psia)	Breather Vent Vacuum Pressure Setting (psia)	Constant Inert Purge Flow Rate (SCFH)	Composition ID
023 A		Slag Sump	14.7002	16.2478	13.2768	0.22	-0.04		
023 B		Slag Sump	14.7002	16.2478	13.2768	0.22	-0.04		
023 C		Slag Sump	14.7002	16.2478	13.2768	0.22	-0.04		C
023 D		Slag Sump	14.7002	16.2478	13.2768	0.22	-0.04		
023 E		Slag Sump	14.7002	16.2478	13.2768	0.22	-0.04		
024		Methanol De-Inventory Tank	4.6184	5.2770	4.0306	0.22	-0.07		
025		Fresh Methanol Storage Tank	4.6184	5.2770	4.0306	0.22	-0.07		
027 A		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
027 B		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
027 C		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
027 D		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
027 E		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
027 F		Sulfuric Acid Storage Tank	0.00027	0.00034	0.00021	0.22	-0.07		
028 A		Aqueous Ammonia	10.89830	12.16068	9.72759	0.22	-0.07		
028 B		Aqueous Ammonia	10.89830	12.16068	9.72759	0.22	-0.07		
029		Diesel	10.56138	11.49227	9.68907	0.22	-0.22		
030		Gasoline	10.88000	11.84900	9.97300	0.22	-0.07		
026		Sour Water Stripper Surge	7.4461	8.1523	6.7986	0.22	-0.07		

TANK IDENTIFICATION		Additional Tank Characteristics								
Unit ID	Tank ID	Tank Common Name	Constant Level?	Bottom Shape	Dome Height (ft.)	Seal Type	Insulated ?	Heated ?	Refrigerated ?	Breathing Loss Evaluation
023 A		Slag Sump	#REF!				No	No	No	3
023 B		Slag Sump	0.00				No	No	No	3
023 C		Slag Sump	onstant Level?				No	No	No	3
023 D		Slag Sump	0.00				No	No	No	3
023 E		Slag Sump					No	No	No	3
024		Methanol De-Inventory Tank	No				No	No	No	3
025		Fresh Methanol Storage Tank	No				No	No	No	3
027 A		Sulfuric Acid Storage Tank					No	No	No	3
027 B		Sulfuric Acid Storage Tank					No	No	No	3
027 C		Sulfuric Acid Storage Tank					No	No	No	3
027 D		Sulfuric Acid Storage Tank					No	No	No	3
027 E		Sulfuric Acid Storage Tank					No	No	No	3
027 F		Sulfuric Acid Storage Tank	No				No	No	No	3
028 A		Aqueous Ammonia					No	No	No	3
028 B		Aqueous Ammonia					No	No	No	3
029		Diesel					No	No	No	3
030		Gasoline					No	No	No	3
026		Sour Water Stripper Surge	No				No	No	No	3

STORAGE TANK PARAMETERS

TANK IDENTIFICATION						Volume		
Unit ID	Tank ID	Tank Common Name	Service	Sp. Gravity	Density lb/gal	MM Gal	Gallons	Lbs
023 A		Slag Sump	Slag	1.22	10.67	0.0253	25,284	269,781
023 B		Slag Sump	Slag	1.22	10.67	0.0253	25,284	269,781
023 C		Slag Sump	Slag	1.22	10.67	0.0253	25,284	269,781
023 D		Slag Sump	Slag	1.22	10.67	0.0253	25,284	269,781
023 E		Slag Sump	Slag	1.22	10.67	0.0253	25,284	269,781
024		Methanol De-Inventory Tank	Methanol		6.64	0.7109	710,896	4,720,347
025		Fresh Methanol Storage Tank	Methanol		6.64	0.3420	342,005	2,270,916
027 A		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
027 B		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
027 C		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
027 D		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
027 E		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
027 F		Sulfuric Acid Storage Tank	Sulfuric Acid		15.10	0.8813	881,276	13,307,262
028 A		Aqueous Ammonia	Ammonia		7.70	0.0322	32,243	248,271
028 B		Aqueous Ammonia	Ammonia		7.70	0.0322	32,243	248,271
029		Diesel	Diesel		7.10	0.0100	9,953	70,663
030		Gasoline	Gasoline		6.10	0.0012	1,175	7,168
026		Sour Water Stripper Surge	Sour Water		8.25	0.1827	182,741	1,507,616

ANTOINES CONSTANTS FOR VARIOUS COMPONENTS (Properties of Gases and Vapor Pressures)

COMPONENT	A	B	C	Max Temp.	Min. Temp.	**VP@300K (Psia)**
1,3-BUTADIENE	15.7727	2142.66	-34.30			
ACETALDEHYDE	7.0564	1070.60	236.10			
ACETIC ACID	7.2996	1479.02	216.81			
ACETONE	16.6513	2940.46	-35.93	350	241	
ACRYLIC ACID	7.5311	1656.57	215.03			
BENZENE	15.9008	2788.51	-52.36	377	280	
BENZOIC ACID	17.1634	4190.70	-125.20	560	405	
BUTANOL	17.2160	3137.02	-94.43	404	288	
ETHANOL	18.9119	3803.98	-41.68	369	270	
ETHYL ACETATE	16.1516	2790.50	-57.15	385	260	
ETHYL ACRYLATE	16.0890	2974.94	-58.15	409	274	
ETHYL ETHER	16.0828	2511.29	-41.95	30	225	11.08433552
ETHYL PROPIONATE	16.1620	2935.11	-64.17	396	276	
FORMIC ACID	7.3778	1563.28	247.06			
ISOBUTANOL	16.8712	2874.73	-100.30	388	293	
ISOBUTYRALDEHYDE	15.9888	2676.98	-51.15	370	247	
ISOPROPYL ETHER	6.9332	1181.30	223.00			
METHANOL	18.5875	3626.55	-34.29	364	257	
METHYL ACETATE	16.1295	2601.92	-56.15	360	245	
METHYL FORMATE	16.5104	2590.87	-42.60	324	225	
MONOETHANOLAMINE	17.8174	3988.33	-86.93	477	344	
NAPHTHALENE	16.1426	3992.01	-71.29	525	360	
N-BUTYRALDEHYDE	16.1668	2839.09	-50.15	380	255	
PHENOL	16.4270	3490.89	-98.59	481	345	
PHTHALIC ANHYDRIDE	15.9984	4467.01	-83.15	615	409	
PROPANE	15.7260	1872.46	-25.16	249	164	
PROPIONALDEHYDE	16.2315	2659.02	-44.15	350	235	
PROPYLENE	15.7027	1807.53	-26.15	240	160	
SULFURIC ACID	7.3456	2421.15	197.80			
VCH	-10.0000	0.00	1.00			
WATER	7.9683	1669.30	228.00			
XYLENE	6.9905	1453.43	215.31			

FUNCTION SYNTAX: VP1("COMPONENT",TEMPERATURE(°R))

ANTOINE VAPOR PRESSURE EQUATION: LN(P)=A-B/(T+C) P as mmHg Exp(A - B / (T + C)) / 760 * 14.7

T as Kelvin

Antoines Constants from "The Properties of Gases and Liquids, 3rd Edition", by Reid, Prausnitz and Sherwood, McGraw Hill, 1977.

ANTOINES CONSTANTS FOR VARIOUS CHEMICALS (TANKS 3.1 CHEMICAL DATABASE)

Chemical	A	B	C
Benzene	6.9050	1211.033	220.790
Ethyl acrylate	7.9645	1897.011	273.160
Ethylbenzene	6.9750	1424.255	213.210
Hexane (-n)	6.8760	1171.170	224.410
Styrene	7.1400	1574.510	224.090
Toluene	6.9540	1344.800	219.480
Xylene	7.0090	1462.266	215.110

1.7634140 1.7459220

Antoines Equation Log10(P) = A - (B / T +C)

P as mmHg

T as °C

Antoines Constants from the Chemical database of Tanks 3.1 program.

FUNCTION SYNTAX: VP2("CHEMICAL",TEMPERATURE(R))

Interpolations

	Temperature (R)					
Chemical	1 mm Hg	10 mm Hg	40 mm Hg	100 mm Hg	400 mm Hg	760 mm Hg
Phenylenediamine	671.64	756.6	819.6	868.2	958.2	1005.9
Hydroquinone	730.32	786.3	837.6	881.7	963.6	1007.16

Vapor Pressures and Temperatures from "Handbook of Chemistry and Physics" 64th edition

FUNCTION SYNTAX: Interp("CHEMICAL",TEMPERATURE(R))

Baghouse Cost Analysis: ZLD Spray Dryer - Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost/yr $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton PM/PM10	Other Impacts
Teflon Fabric Baghouse achieving 0.001 gr/dscf	0.102	0.408	$0	$ 4,381	$ 4,381	$10,700	Marginal increased energy for increased delta P
Baseline - Baghouse controlling to 0.005 gr/dscf	0.5	(proposed)					

ZLD Spray Dryer - Cost Effectiveness to achieve 0.001 gr/dscf (only considering increased bag costs)

Incremental Cost Analysis

For a baghouse to achieve 0.001 gr/dscf versus conventional 0.005 gr/dscf. (increased bag costs only)

Assumptions:

			ZLD Spray Dryer EU-032	Basis (page ref. from EPA Cost Manual (Note 1)
Exhaust Flow	dscf/m		2735	One Unit
Gas to Cloth Ratio	cfm/net ft2		6	page I-22
Net Cloth Requir.	net ft2		455.8	
Gross vs Net cloth	ratio		2	page I-23
Gross cloth requir.	total ft2		911.7	
Teflon Fabric cost	1998$/ft	$	10.958	page I-42 (average)
Ave. Conv. Fabric	1998$/ft	$	0.639	page I-42, polyester or polypropylene
Increased Cost	1998$/ft	$	10.319	
Increased Cost	2011$/ft	$	13.348	assume 2% inflation for 13 years.
Increased cost for bags	Total $	$	12,169	material price (minus tax/freight)
Increased cost for bags	Total $	$	13,143	Price plus 8% tax and freight
Changeout Frequency	years		3	page I-46 (average)
Average annual incremental cost		$	4,381	
Emissions @0.005gr/dscf	tons/yr		0.51	
Emissions decrease at 0.001	ton/yr		0.408	
Cost Effectiveness of Teflon Bags and 0.001 gr/dscf		$	10,738	$/ton controlled

Note: these costs do not include increased costs for higher pressure drop, larger baghouses, or other enhancements to achieve lower performance.

Note 1: EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition, EPA/452/B-02-001 January 2002, Section 6 Chapter 1 Baghouse and Filters

Incremental Cost Analysis for a Baghouse to achieve 0.001 gr/dscf versus baghouse at 0.003 gr/dscf

To achieve 0.001 gr/dscf requires several changes to the baghouse design versus a conventional baghouse, all of which are more expensive. Based on discussions with vendor, Capital costs increase 10%, operating costs increase 15-25%, and the air needs to be heated to avoid condensation on the filter media. These costs are reflected in below incremental capital and operating cost estimates. Baseline Capital and operating costs estimated from EPA's pollution control fact sheet for jet pulse fabric filters. Incremental costs based on above vendor estimated factors.

Process Material Handling EU-011A&B Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost/yr $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton	Other Impacts
Baghouse achieving 0.001 gr/dscf	1.27	2.53	$33,760	$68,027	$72,753	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	3.8	(proposed)					

Incoming Material Handling EU-012 R&S (each 6000 acfm units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr) Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost/yr $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton	Other Impacts
Baghouse achieving 0.001 gr/dscf	0.23	0.45	$6,000	$12,090	$12,930	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.68	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr) Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost/yr $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton	Other Impacts
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

Costs for Fabric Filters Upgrade from 0.003 to 0.001 gr/dscf PM10 Performance

Emissions Unit	**EU-011a/b**			**EU-012 B-0, T-AC**			**EU-012 R/S**		
Air Flow Rate (ACF/M)	**33760**			**1500**			**6000**		
	0.003 gr/dscf	0.001 gr/dscf	**Delta**	0.003 gr/dscf	0.001 gr/dscf	**Delta**	0.003 gr/dscf	0.001 gr/dscf	**Delta**
Total Capital Investment (Note 1, Note 2)	$337,600	$371,360	**$33,760**	$15,000	$16,500	**$1,500**	$60,000	$66,000	**$6,000**
Annual Costs									
Total Direct Costs			**Delta**			**Delta**			**Delta**
Labor, Maintenance, Replacement Bags, etc. (Note 3, Note 4)	$303,840	$349,416	**$45,576**	$13,500	$15,525	**$2,025**	$54,000	$62,100	**$8,100**
Energy to keep air above dew point (prevent condensation) (Note 5)		$22,451	**$22,451**		$998	**$998**		$3,990	**$3,990**
Subtotal Annual Direct Costs									
Indirect Costs									
Capital Recovery (Capital * 0.14 assuming 7% interest and 10 yr life)	$47,264	$51,990	**$4,726**	$2,100	$2,310	**$210**	$8,400	$9,240	**$840**
Total Annual Costs	$351,104	$423,857	**$72,753**	$15,600	$18,833	**$3,233**	$62,400	$75,330	**$12,930**
Emissions (tons/yr) if run 8760hr/yr at design outlet grain loading	3.80	1.27	**2.53**	0.17	0.06	**0.11**	0.68	0.23	**0.45**
Incremental Cost Effectiveness ($/Ton to improve control from 0.003 to 0.001 gr/dscf)			**$28,701**			**$28,701**			**$28,701**

Note 1 Capital to achieve 0.003 gr/dscf based on $10/acfm conservatively based on lower end of range of costs from EPA Pollution Control Fact Sheet for Jet Pulse Fabric Filters (Sixth Edition, EPA/452/B-02-001, January 200
Note 2 Capital costs estimated to increase at least 10% to achieve 0.001 gr/dscf per vendor
Note 3 Annual costs (excluding capital recovery) for 0.003 gr/dscf based on 9$/acfm conservatively based on lower end of range of costs from EPA Fact Sheet for Jet Pulse Filters
Note 4 Annual costs estimated to increase at least 15% to achieve 0.001 gr/dscf per vendor
Note 5 Energy costs to keep filtered air above dew point assume 10 degF temperature rise, energy costs $7/MMBtu, air heat capacity of 0.241 btu/lb-F, and air density 0.075 lb/ft

General Explaintion of Above Calculations: To achieve 0.001 gr/dscf requires several changes to the baghouse design versus a conventional baghouse, all of which are more expensive. Based on discussions with vendor, Capital costs increase 10%, operating costs increase 15-25%, and the air needs to be heated to avoid condensation on the filter media. These costs are reflected in below incremental capital and operating cost estimates. Baseline Capital and operating costs estimated from EPA's pollution control fact sheet for jet pulse fabric filters. Incremental costs based on above vendor estimated factors.

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)

Source Background and Description

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Proposed Construction

Indiana Gasification, LLC is proposing to install a new source in Spencer County, the proposed facility is designed to convert Illinois Basin coal and petroleum coke into pipeline-quality SNG and liquefied CO_2. The project will produce up to 48 billion standard cubic feet (Bscf) of SNG annually utilizing approximately 3.5 million tons of feedstock. About 39 Bscf will be sold to the Indiana Finance Authority ("IFA") for use by Indiana natural gas consumers with the remaining sold in the natural gas marketplace. The project will also produce annually up to approximately 6.43 million tons of liquefied CO_2 that will be sold to third parties for use in Enhanced Oil Recovery ("EOR") where it is estimated to produce approximately 10,000,000 barrels per year of additional domestic oil in the Gulf Coast region.

The facility will have several products in addition to SNG and liquefied CO_2. Sulfur compounds in the feedstocks will be processed into sulfuric acid, which IG plans to sell into the industrial market. Argon will be recovered from the air separation unit and sold to one or more industrial gas companies. Heat generated during the gasification process will be used to produce steam for steam turbines that can produce approximately 300 MW, primarily to meet on-site power needs. Depending on process and ambient conditions, a small amount of power will be exported into or imported from the nearby electrical transmission system. Indiana Gasification, LLC is required to undergo a review of control technology for pollutants above PSD threshold and significant levels under Federal and State Prevention of Significant Deterioration (PSD) regulations.

Indiana Gasification, LLC, located at CR 200 N and Base Road, Rockport, Indiana in Spencer County submitted a PSD and Title V operating permit application to IDEM, OAQ on April 20, 2011,

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 New Source review because the new construction has the potential to emit of CO emissions greater than 100 tons per year, which exceed the PSD threshold and significant levels for this pollutant. The BACT review also addressed the following pollutants PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, H_2SO_4 and GHGs that exceeded the PSD significant levels.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

Proposed New Emission Units

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed modification for the following emission units:

(A) Incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins, consisting of: [Under 40 CFR 60, Subpart Y, the incoming solid feedstock materials handling system, transferring material from the barge unloading facility and railcar unloading facility to storage piles and day bins are new affected sources.]

  (1) One (1) barge unloading to hopper transfer point, to be permitted in 2012, nominally rated at 750 tons per hour, identified as EU-012A, with particulate emissions controlled by wet suppression.

  (2) The following twenty (20) transfer points, each with particulate emissions controlled with a dust extraction system or baghouse nominally rated at 1,500 acfm:

    (a) One (1) barge unloading from the hopper to the belt, identified as EU-012B, to be permitted in 2012, with one (1) control device, identified as C-012B, exhausting through one (1) vent, identified as S-012B;

    (b) Four (4) barge conveyor transfer points, identified as EU-012C through EU-012F, to be permitted in 2012, with four (4) control devices, identified as C-012C through C-012F, respectively, exhausting through four (4) vents, identified as S-012C through S-012F, respectively;

    (c) Two (2) rail unloading to rail hoppers, identified as EU-012G and EU-012H, to be permitted in 2012, with two (2) control devices, identified as C-012G through C-012H, respectively, exhausting through two (2) vents, identified as S-012G through S-012H, respectively;

    (d) Two (2) rail hoppers unloading to the conveyor belts, identified as EU-012I and EU-012J, to be permitted in 2012, with two (2) control devices, identified as C-012I and C-012J, respectively, exhausting through two (2) vents, identified as S-012I through S-012J, respectively;

    (e) One (1) rail conveyor belt to the stacker, identified as EU-012K, to be permitted in 2012, with one (1) control device, identified as C-012K, exhausting through one (1) vent, identified as S-012K;

    (f) Two (2) stacker belts to the radial stacker, identified as EU-012L and EU-012M, to be permitted in 2012, with two (2) control devices, identified as C-012L and C-012M, respectively, exhausting through two (2) vents, identified as S-012L through S-012M, respectively;

    (g) Two (2) classification towers, identified as EU-012T and EU-012U, to be permitted in 2012, with two (2) control devices, identified as C-012T and C-012U, respectively, exhausting through two (2) vents, identified as S-012T through S-012U, respectively; and

(h) One (1) classification tower to a day bin, identified as EU-012V, to be permitted in 2012, with one (1) control device, identified as C-012V, exhausting through one (1) vent, identified as S-012V;

(i) Three (3) truck stations unloading to a truck hopper, identified as EU-012Z, EU-012AB and EU-012AC, to be permitted in 2012, with three (3) control devices, identified as C-012Z, C-012AB and C-012AC, respectively, exhausting through three (3) vents, identified as S-012Z, S-012AB and S-012AC, respectively;

(j) One (1) truck hopper unloading to the conveyor belts, identified as EU-012AA, to be permitted in 2012, with one (1) control device, identified as C-012AA exhausting through one (1) vent, identified as S-012AA; and

(k) One (1) truck/rail conveyor transfer tower, identified as EU-012Y, to be permitted in 2012, with one (1) control device, identified as C-012Y, exhausting through one (1) vent, identified as S-012Y;

(3) Two (2) radial stackers to the pile, nominally rated at 3,000 tons per hour each, to be permitted in 2012, with particulate emissions controlled by telescoping chutes with two (2) fabric filters identified as C-012N and C-012O, exhausting through two (2) stacks, identified as S-012N and S-012O.

(4) Two (2) transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers, identified as EU-012R and EU-012S, to be permitted in 2012, with particulate emissions controlled with two (2) dust extraction systems or baghouses, identified as C-012R and C-012S, respectively, each nominally rated at 6,000 acfm, exhausting through two (2) vents, identified as S-012R and S-012S, respectively.

(5) Two (2) dozer activities on the piles, nominally rated at 1,500 tons per hour each, identified as EU-012P and EU-012Q, to be permitted in 2012, with particulate emissions controlled by wet suppression.

(6) Two (2) storage piles with a nominal capacity of 300,000 tons each, identified as EU-012W and EU-012X, to be permitted in 2012, with particulate emissions controlled by wet suppression and compaction.

(B) Two (2) process area solid feedstock conveying, storage, and feed bins (main and spare), identified as EU-011A and EU-011B, to be permitted in 2012, with particulate emissions controlled by two (2) baghouses identified as C-011A and C-011B, respectively, each nominally rated at 33,760 dscfm, exhausting through two (2) stacks, identified as S-011A and S-011B, respectively. [Under 40 CFR 60, Subpart Y, the process area solid feedstock conveying, storage, and feed bins (main and spare) are new affected sources.]

(C) One (1) syngas hydrocarbon flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-001, to be permitted in 2012, exhausting through one (1) tip, identified as S-001.

(D) One (1) acid gas flare, with a pilot nominally rated at 0.27 MMBtu/hr HHV and identified as EU-002, to be permitted in 2012, exhausting through one (1) tip, identified as S-002.

(E) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, to be permitted in 2012, with methanol, H_2S, COS, and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

(F) Two (2) Wet Sulfuric Acid (WSA) plant trains, each nominally rated at 800 stpd H_2SO_4 and identified as EU-015A and EU-015B, to be permitted in 2012, with NO_x, SO_2, H_2SO_4 emissions controlled by two (2) selective catalytic reduction (SCR) systems identified as C-015-1A and C-015-1B, respectively, and two (2) hydrogen peroxide scrubbers identified as C-015-2A and C-015-2B, respectively, exhausting through two (2) stacks, identified as S-015A and S-015B respectively. These emissions units also include two (2) preheat burners (one for each train), each nominally rated at 35.00 MMBtu/hr HHV, venting through the same stacks.

(G) Two (2) natural gas-fired auxiliary boilers, nominally rated at 408 MMBtu/hr HHV each, identified as EU-005A and EU-005B, to be permitted in 2012, with NO_x emissions controlled by ultra-low NO_x burners/Flue Gas Recirculation (ULNB/FGR), with both boilers exhausting through one (1) stack, identified as S-005. [Under 40 CFR 60, Subpart Db, the natural gas-fired auxiliary boilers are new affected sources.]

(H) Five (5) natural gas-fired and SNG fuel-fired gasifier preheat burners, each nominally rated with a heat input of 35.00 MMBtu/hr HHV, and identified as EU-008A through EU-008E, to be permitted in 2012, exhausting through five (5) vents, identified as S-008A through S-008E, respectively.

(I) One (1) ZLD-Spray Dryer, to be permitted in 2012, nominally rated at 5.6 MMBtu/hr with PM emissions controlled by a baghouse identified as C-032, nominally rated at 2,735 dscfm, and identified as EU-032, with low NOx burners (LNB), exhausting through one (1) stack, identified as S-014.

(J) Methanol Tanks:

(1) One (1) Methanol De-Inventory Tank, with a nominal capacity of 700,000 gallons, identified as EU-024, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-024. [40 CFR 60 Subpart Kb].

(2) One (1) Fresh Methanol Storage Tank, with a nominal capacity of 332,000 gallons, identified as EU-025, to be permitted in 2012, with emissions controlled by a vapor recovery system and exhausting through one (1) vent, identified as S-025. [40 CFR 60 Subpart Kb]

(k) Paved Plant Haul Roads are identified as emissions unit FUG-ROAD.

(L) Electrical Circuit Breakers (approximately six) containing sulfur hexafluoride (SF_6) identified as emissions unit FUG-SF6, to be permitted in 2012, with fugitive GHG emissions controlled by full enclosure.

(M) Fugitive Equipment Leaks from the gasification, shift conversion, gas cooling, AGR, CO_2 compression, WSA, and methanation are identified as emissions units FUG and FUG-WSA and will be controlled by a Leak Detection and Repair (LDAR) program.

(N) Two (2) emergency diesel generators, each nominally rated at 1,341 horsepower, identified as EU-009A and EU-009B, to be permitted in 2012, exhausting through two (2) vents, identified as S-009A and S-009B, respectively. [Under 40 CFR 60, Subpart IIII, each, emergency diesel fired generator is considered a new affected source.][Under 40

CFR 63, Subpart ZZZZ, each, emergency diesel fired generator is considered a new affected source.]

(O) Three (3) firewater pump diesel engines, each nominally rated at 575 horsepower and identified as EU-010A through EU-010C, to be permitted in 2012, exhausting through three (3) vents, identified as S-010A through S-010C, respectively. [Under 40 CFR 60, Subpart IIII, each firewater pump diesel engine is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, each firewater pump diesel engine is considered a new affected source.]

(P) Four (4) rod mill eductor vent stacks, to be permitted in 2012, nominally rated at 180 cfm and identified as EU-013A through EU-013D, and exhausting through four (4) vents, identified as S-013A through S-013D, respectively.

(Q) One (1) six (6) cell ASU cooling tower, nominally rated with a circulation rate of 54,960 gpm and identified as EU-016A, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through six (6) vents, identified as S-016A-A through S-016A-F.

(R) One (1) twenty-four (24) cell main cooling tower, nominally rated with a circulation rate of 404,700 gpm and identified as EU-016B, to be permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through twenty-four (24) vents, identified as S-016B-A through S-016B-X.

(S) Two (2) Air Separation Unit (ASU) molecular sieve regeneration train vent, which each vent a nominal 187,000 cubic feet per minute during regenerations, identified as EU-017A and EU-017B, to be permitted in 2012, exhausting through two (2) vents, identified as S-017A andS-017B, respectively.

(T) One (1) slag handling storage pad, to be permitted in 2012, nominally rated at 43 tons per hour, identified as EU-034A, with fugitive particulate emissions controlled by wet suppression.

(U) One (1) front-end loader activity on the slag storage pad, to be permitted in 2012, nominally rated at 1,440 tons per day, identified as EU-034C, with fugitive particulate emissions controlled by wet suppression.

(V) Six (6) fixed roof sulfuric acid storage tanks, to be permitted in 2012, each with a nominal capacity of 866,500 gallons - identified as EU-027A through EU-027F.

(X) One (1) ZLD Inert Gas Vent identified as EU-033, to be permitted in 2012, with mercury (Hg) emissions controlled by a sulfided carbon adsorbent identified as C-033, exhausting through one (1) stack, identified as S-033.

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 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. There will still be air pollution from this project; however, Indiana Gasification, LLC will be required to demonstrate that the emissions will be reduced to maximum extent.

Federal EPA generally requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. IDEM evaluates BACT based on a "top down" approach.

The five (5) basic steps of a top-down BACT analysis used by the Office of Air Quality (OAQ) to make BACT determinations are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls if proposed by the source. Indiana Gasification, LLC has not submitted any innovative control technology. Only available and proven control technologies are evaluated. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of control effectiveness (percent pollutant removed). 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 begins with an evaluation of the remaining technologies under consideration for each pollutant of concern in regards to energy, environmental, and economic impacts for determining a final control technology. The highest ranked alternative is evaluated for environmental, energy and economic impacts specific to the proposed modification. If the analysis determines that the highest ranked control is not appropriate as BACT, due to any of the energy, environmental, and economic impacts, then the next most effective control is evaluated. The evaluation continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical, economic or environmental analysis for a greenhouse gas BACT. An Air Quality Impact Analysis would be required for a non-greenhouse gas BACT.

Step 5: Select BACT

The most effective option not eliminated in step 4 is BACT.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT – Syngas Hydrocarbon Flare (EU-001)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;
(2) Process flaring minimization practices (Flare Minimization Plan); and
(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Each option listed above is evaluated as follows:

Flare design and proper operation
Flare design and operation are key elements in the emissions performance of flares. The IG syngas hydrocarbon flare will be designed and operated to be smoke-free, thereby minimizing emissions. The fact that all gases vented to the flare will be low molecular weight helps assure low particulate creation. The flare's natural draft will draw in sufficient oxygen to ensure complete combustion of the flared gases.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare design and proper operation is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Process flaring minimization practices
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM, PM_{10} and $PM_{2.5}$ will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Process flaring minimization practices is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Flare gas recovery
Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.
(2) Another significant difference is that the process off gas flows in refineries are frequent enough to justify a fuel gas cleanup system and it operates at less than 100 psig. In contrast, the IG facility's syngas flaring will be infrequent and the analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare gas recovery is not a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Proper flare design and operation;

(2) Process flaring minimization practices (Flare Minimization Plan).

These two controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies are needed.

Flare Design and Operation

The flare design will be inherently efficient at ensuring complete combustion and minimizing PM/ PM_{10}/$PM_{2.5}$ emissions. The flares will be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

Process flaring minimization practices (Flare Minimization Plan)

There are a number of steps that can be taken in the operation of the facility that will reduce the volume of gases flared and thereby the emissions of particulates. During a planned shutdown of a gasifier, the contents of the gasifier (gasifier vessel, quench chamber, scrubber vessel) can be routed, during initial depressurization, to one of the Wet Sulfuric Acid (WSA) plants. Also, the feed rate to the gasifiers can be reduced such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare. Also, the permittee can investigate the “root cause” of malfunction events that cause gases to be sent to the flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Syngas Hydrocarbon Flare (EU-001)**	**10,400 T dry coal/day, 48 BSCF/yr SNG**	**PM/PM10 3.21 lbs/hr (3 hr ave); PM2.5 3.01**	**Proper design and Operation, Flare Minimization Plan**

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
					lbs/hr (3 hr ave),	
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	001 Gasifier Flare *	9, 413 T coke/day	6.42 lb/hour	Good Design and monitoring to ensure the presence of a flame at the flare tip at all the time.
Permit V-09-006 Kentucky	Cash Creek **Gasification	05/05/2010	Flare *	770 MW (36.8 BSCF/yr SNG)	0.24 lb/hr PM10 at startup, 0.0302 lb/MMBtu standby (3 hr ave)	No control
V-09-006 Kentucky	Ky Syngas, Kentucky	09/24/2010	Flare	70 Billion SCF/yr SNG	NA	NA
28.0701-PSD South Dakota	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063) Illinois	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,700 T coal per day	15.4 lb/SSM event	Flare minimization plan,
T083-23529-00003 Indiana	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	618 MW ~ 5000 tons coal/day	1.5 lb/hr during peak of startup	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.
**The Cash Creek Permit does not require testing of the emission limit.

The low emissions rate for PM of 0.24 lb/hr in Cash Creek's permit appears to be an artifact of the emissions factor used, not a meaningful difference in flared gases. Cash Creek emissions of other criteria pollutants from flaring besides PM are consistent with other facilities. The Cash Creek PM estimate is listed in their application as based on "vendor provided" emissions. This may only include pilot emissions since AP-42 lists no factor for PM/soot from non-smoking flare (see Ap-42 Chapter 13.5, Table 13.5-1). In contrast, IDEM, OAQ conservatively estimated PM using AP-42 natural gas external combustion PM factor of 0.0075 lb total PM/mmbtu (AP-42 Chapter 1.4, Table 1.4-2).

Proposal: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Syngas Hydrocarbon Flare (EU-001):

(1) Comply with the following Flare Minimization Plan to reduce PM, PM_{10} and $PM_{2.5}$ emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(2) Comply with the following best practices for flare design and operation:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

(B) Flares shall be operated with a flame present at all times.

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(3) The Syngas Hydrocarbon Flare PM/PM_{10} emissions shall not exceed 3.21 lb/hour during startup or shutdown, based on a 3-hour average.

(4) Based on the ratio of PM2.5 to total PM from the EPA PM calculator, the Syngas Hydrocarbon Flare $PM_{2.5}$ emissions shall not exceed 3.01 lb/hour during startup or shutdown, based on a 3-hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Syngas Hydrocarbon Flare (EU-001).

(1) Comply with the following Flare Minimization Plan to reduce PM, PM_{10} and $PM_{2.5}$ emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(2) Comply with the following best practices for flare design and operation:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

(B) Flares shall be operated with a flame present at all times.

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

(3) The Syngas Hydrocarbon Flare PM/PM_{10} emissions shall not exceed 3.21 lb/hour during startup or shutdown, based on a 3-hour average.

(4) The Syngas Hydrocarbon Flare $PM_{2.5}$ emissions shall not exceed 3.01 lb/hour during startup or shutdown, based on a 3-hour average.

Carbon Monoxide (CO) BACT – Syngas Hydrocarbon Flare (EU-001)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare CO emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

CO controls that may be used on other types of sources, such as catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation

Flare design and proper operation– Flare design and operation are key elements in the emissions performance of flares. The source is proposing the use of elevated flares which have very high combustion efficiency. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented gases.

A potential alternative flare design is an enclosed or ground flare. However, enclosed or ground flares are no more effective in destruction. Additionally, enclosed flares are not typically considered for high flow rate situations. An evaluation of typical enclosed flare designs indicates that the commercial designs that have been demonstrated are for landfill gas (low flow rates and low heating value) and upstream oil and gas operations (low flow rates and high heating values). These flare designs and controls are not technically feasible for this high gas flow, lower heating value application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare design and proper operation is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Process flaring minimization practices (Flare Minimization Plan)
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a process flaring minimization practices is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.

(2) Another significant difference is that refineries can recover flare gas into their fuel gas cleanup system which operates at less than 100 psig. In contrast, the IG facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor versus those at refineries.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare Gas Recovery is not a technically feasible option for the syngas hydrocarbon flare at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Flare design and proper operation

(2) Process flaring minimization practices

These two controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies are needed.

Flare Design and Operation
The design of the flares is specific for the process stream that will be controlled and includes the following considerations:

(1) The flares are designed specifically for use during startup, shutdown or upset conditions; therefore, they will be optimized for potential gas flow and gas compositions with ample pilot burners to ensure very high combustion efficiency.

(2) The raw syngas stream contains CO, NH_3 and HCN that require oxidation for control. US EPA research indicates that 99.5% oxidation efficiency (CO) is achievable in well-designed flares

(Flare Efficiency Study, USEPA, EPA-600-83-052, July 1983.) The stream also contains H_2S and COS that require conversion to SO_2, as well as NH_3 and HCN that require conversion to N_2, H_2O and CO_2 for control. Ninety eight percent (98%) oxidation efficiency of H_2S and COS and NH_3 are reasonable given the oxidation efficiency of the main fuel components H_2 and CO.

(3) In the event of an SNG compressor trip, the flared stream will be predominantly methane and will have a constant flow. The flare will destroy the methane with a control efficiency of 98%.

(4) Flare Best Practices:

- Flares will be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
- Flares will be operated with a flame present at all times.
- Flares will be monitored to ensure that operation and maintenance is in conformance with the above designs.
- Flares will be operated at all times when emissions are vented to them.

Process flaring minimization practices

There are a number of steps that can be taken in the operation of the facility that will reduce the volume of gases flared and thereby the emissions. During a planned shutdown of a gasifier, the contents of the gasifier (gasifier vessel, quench chamber, scrubber vessel) can be vented, during initial depressurization, to one of the Wet Sulfuric Acid (WSA) plants. Also, the feed rate to the gasifiers can be reduced such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare. Also, the permittee can investigate the “root cause” of malfunction events that cause gases to be sent to the flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Syngas Hydrocarbon Flare (EU-001)**	**10,400 T dry coal/day, 48 BSCF/yr SNG**	**172.4 lb/hr (3 hr ave)**	**Proper design and Operation, Flare Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	001 Gasifier Flare *	9, 413 T coke/day	44.7 lb/hr	Good Design and monitoring to ensure the presence of a flame at the flare tip at all the time.
Permit V-09-006 - Kentucky	Cash Creek Gasification	05/05/2010	Flare *	770 MW (36.8 BSCF/yr SNG)	352.96 lb/hr CO at startup, 0.3345 lb/MMBtu	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
					standby (3 hr ave)	
V-09-006 - Kentucky	Ky Syngas, Kentucky	09/24/2010	Flare	70 Billion SCF/yr SNG	14,951 lb/hr (8 hr ave) 604.5 ton/yr	NA
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,700 T coal per day	1,279 lb/SSM event	Flare minimization plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	618 MW ~ 5000 tons coal/day	898 lb/hr during peak of startup, 72.9 tons/yr	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Syngas from gasifier startup and shutdown will contain a high CO and H_2 concentration and very low concentrations of hydrocarbons. Syngas combustion at the flare tip will be oxidizing CO to CO_2 with negligible CO generated by combustion of hydrocarbon compounds. CO oxidation will be facilitated by the high syngas hydrogen concentration. Hydrogen has a low ignition energy so it will readily ignite and completely combust. The resulting uniform high temperature will promote CO combustion resulting in 99.5% oxidation efficiency.

Proposal: **Indiana Gasification, LLC – Rockport, IN**

1. Comply with the following Flare Minimization Plan to reduce CO emissions during startups, shutdowns, and other flaring events.

   During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

   The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

   The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

   The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

2. Comply with the following flare best practices:

   A. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
   B. Flares shall be operated with a flame present at all times.
   C. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

3. The Syngas Hydrocarbon Flare CO emissions shall not exceed 172.4 lb/hour during startup or shutdown, based on a 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Syngas Hydrocarbon Flare (EU-001).

1. Comply with the following Flare Minimization Plan to reduce CO emissions during startups, shutdowns, and other flaring events.

   During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

   The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

   The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

   The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

2. Comply with the following flare best practices:
   A. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
   B. Flares shall be operated with a flame present at all times.
   C. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

3. The Syngas Hydrocarbon Flare CO emissions shall not exceed 172.4 lb/hour during startup or shutdown, based on a 3 hour average.

Sulfur Dioxide (SO_2) BACT - Syngas Hydrocarbon Flare (EU-001)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare SO_2 emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

Add-on SO_2 controls that may be used on other types of sources, such as scrubbers, are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and proper operation – Flare design and monitoring are key elements in the emissions performance of flares. However, SO_2 emissions are merely a function of the amount of sulfur compounds in the gases vented to the flare and are unrelated to flare design. Therefore, for SO_2 purposes, flare design is not considered further.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare design and proper operation is not a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Process flaring minimization practices (Flare Minimization Plan)
To the extent actions can be taken to minimize the volume of gas going to the flare, whatever its sulfur content, emissions of SO_2 will be less. Also, there are steps that can be taken to reduce the sulfur compounds in the gas going to the flare during certain situations. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Process flaring minimization practices is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the IG facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.

(2) Another significant difference is that refineries can recover flare gas into their fuel gas cleanup system which operates at less than 100 psig. In contrast, the IG facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor versus those at refineries.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare gas recovery is not a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Process flaring minimization practices (Flare Minimization Plan)

The control listed above is proposed to be implemented by the source and only one option has been identified, therefore, no ranking of control technologies is needed.

Process flaring minimization practices
There are a number of steps that can be taken in the operation of the facility that will reduce the volume of gases flared and thereby the emissions of SO2. First, the gasifiers can be started on a low sulfur feedstock rather than coal or coke, thereby reducing the sulfur compounds in the gas going to the flare during startup. During a planned shutdown of a gasifier, the contents of the gasifier (gasifier vessel, quench chamber, scrubber vessel) can be vented, during initial depressurization, to one of the Wet Sulfuric Acid (WSA) plants. Also, the feed rate to the gasifiers can be reduced such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare. Also, the permittee can investigate the “root cause” of malfunction events that cause gases to be sent to the flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Syngas Hydrocarbon Flare (EU-001)**	**10,400 T dry coal/day, 48 BSCF/yr SNG**	**0.35 lb/hr (3 hr ave) startup on sulfur free fuel 85.21 lb/hr (3 hr ave) for shut down**	**Flare Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	001 Gasifier Flare *	9, 413 T coke/day	0.7 lb/hr (applies to startup emissions)	no control
Permit V-09-006 - Kentucky	Cash Creek Gasification	05/05/2010	Flare *	770 MW (36.8 BSCF/yr SNG)	1.0 lb/hr SO2 at startup, 0.0024 lb/MMBtu standby	None
V-09-006 Kentucky	Ky Syngas, Kentucky	09/24/2010	Flare	70 Billion SCF/yr SNG	33.8 lb/hr (24 hr ave)	NA
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of	10/26/2009	Flare *	13,700 T coal per day	9510lb/SSM event	Flare minimization plan,

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	Illinois Gasification					
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	618 MW ~ 5000 tons coal/day	1396.7 lb/hr during peak of startup	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Indiana Gasification and Cash Creek have proposed the use of sulfur-free fuel for startup, resulting in minimal SO2 emissions from Startup flaring. The other above facilities, which show significantly higher emissions, likely propose to use coal or other sulfur-containing fuel for startup.

Proposal: **Indiana Gasification, LLC** – Rockport, IN

1. Comply with the following Flare Minimization Plan to reduce SO_2 emissions during startups, shutdowns, and other flaring events.

   The use of methanol, rather than coal or pet coke, as the feedstock in each gasifier during startup conditions requiring syngas flaring, thereby reducing emissions of sulfur dioxide at the syngas hydrocarbon flare

   During a planned shutdown of a gasifier, routing the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel), during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

   Reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

   Investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures would be implemented and documented.

The SO_2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lb per 24 hours. The SO_2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for Syngas Hydrocarbon Flare (EU-001).

1. Comply with the following Flare Minimization Plan to reduce SO_2 emissions during startups, shutdowns, and other flaring events.

The permittee will use methanol, rather than coal or pet coke, as the feedstock in each gasifier during startup conditions requiring syngas flaring, thereby reducing emissions of sulfur dioxide at the syngas hydrocarbon flare

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

2. The SO_2 emissions from the Syngas Hydrocarbon Flare during a shutdown event shall not exceed 85.21 lb/hr based on a 3-hour average and shall not exceed 255.6 lb per 24 hours. The SO_2 emissions from the Syngas Hydrocarbon Flare shall not exceed 0.35 lb/hour during startup, based on a 3 hour average.

Nitrogen Oxide (NO_X) BACT - Syngas Hydrocarbon Flare (EU-001)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare NOx emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;
(2) Process flaring minimization practices (Flare Minimization Plan); and
(3) Flare gas recovery.

Certain NOx controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and proper operation – Flare design and monitoring are key elements in emissions performance of flares. However, NOx emissions are not greatly affected by flare design. Instead, flare NOx is primarily a function of the amount of material flared and its nitrogen content. The open-flame nature of a flare results in inherently good NOx performance and prohibits the use of design features used on conventional low NOx or ultra - low NOx gas burners in heaters and boilers. There are no flare burner tips available for low NOx performance on a high volume emergency flare.

The source is proposing the use of elevated flares. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented gases. A potential alternative flare design is an enclosed or ground flare. However, enclosed flares are not typically considered for high flow rate situations. An evaluation of typical enclosed flare designs indicates that the commercial designs that have been demonstrated are for landfill gas (low flow rates and low heating value) and upstream oil and gas operations (low flow rates and high heating values). These flare designs and controls are not technically feasible for this high gas flow, lower heating value application.

Therefore, no flare design or operational features were identified as applicable for NOx control. Therefore, these flare designs and controls are not technically feasible for this, high gas flow, lower heating value application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare design and proper operation is not a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Process flaring minimization practices (Flare Minimization Plan)
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Process flaring minimization practices is a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the IG facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.

(2) Another significant difference is that refineries can recover flare gas into their fuel gas cleanup system which operates at less than 100 psig. In contrast, the IG facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor versus those at refineries.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare gas recovery is not a technically feasible option for the Syngas Hydrocarbon Flare (EU-001) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technology for the flare is:

(1) Process flaring minimization practices (Flare Minimization Plan)

Process flaring minimization practices

There are a number of steps that can be taken in the operation of the facility that will reduce the volume of gases flared and thereby the emissions. During a planned shutdown of a gasifier, the contents of the gasifier (gasifier vessel, quench chamber, scrubber vessel) can be vented, during initial depressurization, to one of the Wet Sulfuric Acid (WSA) plants. Also, the feed rate to the gasifiers can be reduced such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare. Also, the permittee can investigate the "root cause" of malfunction events that cause gases to be sent to the flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events.

The only control listed above is proposed to be implemented by the source; therefore, no ranking of any control technology is needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Syngas Hydrocarbon Flare (EU-001)**	**10,400 T coal/day, 48 BSCF/yr SNG**	**43.09 lb/hr (3 hr ave)**	**Flaring Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	001 Gasifier Flare *	9, 413 T coke/day	86.28 lb/hr	No control.
Permit V-09-006- Kentucky	Cash Creek Gasification	05/05/2010	Flare *	770 MW (36.8 BSCF/yr SNG)	51.0 lb/hr NOx at startup (3 hr ave)	None
V-09-006 Kentucky	Ky Syngas, Kentucky	09/24/2010	Flare	70 Billion SCF/yr SNG	324.1 lb/hr (24 hr ave) 19.5 tons/yr	NA
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,700 T coal per day	513 lb per SSM event	Flare Minimization Plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	618 MW ~ 5000 tons coal/day	182.4 lb/hr during peak of startup, 22.1 tons/yr	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Proposal: **Indiana Gasification, LLC** – Rockport, IN

Process flaring minimization practices

1. Comply with the following Flare Minimization Plan to reduce NOx emissions during startups, shutdowns, and other flaring events.

   During a planned shutdown of a gasifier, route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

   Reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

   Investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures can then be implemented.

2. The Syngas Hydrocarbon Flare NOx emissions shall not exceed 43.09 lb/hour during startup or shutdown, based on a 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Syngas Hydrocarbon Flare (EU-001).

1. Comply with the following Flare Minimization Plan to reduce NOx emissions during startups, shutdowns, and other flaring events.

   During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

   The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

   The permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

   The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

2. The Syngas Hydrocarbon Flare NOx emissions shall not exceed 43.09 lb/hour during startup or shutdown, based on a 3 hour average.

Particulate (PM, PM10 and PM2.5) BACT –Acid Gas Flare (EU-002)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare PM, PM_{10} and $PM_{2.5}$ emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

Add-on PM, PM_{10} and $PM_{2.5}$ controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and operation are key elements in the emissions performance of flares. The source's acid gas flare will be designed and operated to be smoke-free, thereby minimizing emissions. The flare’s natural draft will draw in sufficient oxygen to ensure complete combustion of the flared gases.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare design and proper operation is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Process flaring minimization practices (Flare Minimization Plan)
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of PM/PM_{10} will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a process flaring minimization practices is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Flare gas recovery
Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery’s nearly continuous supply of flared gases, flaring at the Acid Gas Flare will be extremely infrequent. No non-emergency flaring is anticipated.

(2) Another issue is that during most upset scenarios of the IG acid gas flares, the WSA itself (the normal disposition of the acid gas) is likely either in the process of being started up, in an upset, or otherwise not ready to receive the acid gases.

(3) Given the extremely infrequent nature of acid gas flaring, and given the likely lack of a reasonably compatible outlet for recovered gases at the time of acid gas flaring events, flare gas recovery is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare Gas Recovery is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Flare design and proper operation

(2) Process flaring minimization practices (Flare Minimization Plan)

These two controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies are needed.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Flare (EU-002)**	**10,400 T dry coal/day**	**None**	**Proper design and Operation, Flare Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	002 Acid Gas Flare *	9, 413 T coke/day	None	Good Design and monitoring to ensure the presence of a flame at the flare tip at all the time.
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,722 T coal per day	None	Flare minimization plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	630 MW	None	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Proposal: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Acid Gas Flare (EU-002):

(1) The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that

can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(2) Comply with the following best practices for flare design and operation:

(A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

(B) Flares shall be operated with a flame present at all times.

(C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Acid Gas Flare (EU-002).

1. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented

2. Comply with the following flare best practices:
   A. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
   B. Flares shall be operated with a flame present at all times.
   C. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

Carbon Monoxide (CO) BACT – Acid Gas Flare (EU-002)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare CO emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and Proper Operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

CO controls that may be used on other types of sources, such as catalytic oxidation are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and proper operation– Flare design and monitoring are key elements in the emissions performance of flares. The source is proposing the use of elevated flares which have very high combustion efficiency. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented

gases. Maintaining the presence of a flame and operating the flare without visible emissions will ensure efficient combustion and minimization of CO emissions.

A potential alternative flare design is an enclosed or ground flare. However, enclosed or ground flares are no more effective in destruction. Additionally, enclosed flares are not typically considered for high flow rate situations. An evaluation of typical enclosed flare designs indicates that the commercial designs that have been demonstrated are for landfill gas (low flow rates and low heating value) and upstream oil and gas operations (low flow rates and high heating values). These flare designs and controls are not technically feasible for this high gas flow, lower heating value application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flare design and proper operation is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Process flaring minimization practices (Flare Minimization Plan)
Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of process flaring minimization practices is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the Acid Gas Flare will be extremely infrequent. No non-emergency flaring is anticipated.

(2) Another issue is that during most upset scenarios of the IG acid gas flares, the WSA itself (the normal disposition of the acid gas) is likely either in the process of being started up, in an upset, or otherwise not ready to receive the acid gases.

(3) Given the extremely infrequent nature of acid gas flaring, and given the likely lack of a reasonably compatible outlet for recovered gases at the time of acid gas flaring events, flare gas recovery is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare gas recovery is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Flare design and proper operation

(2) Process flaring minimization practices (Flare Minimization Plan)

These two controls listed above are proposed to be implemented by the source, therefore, no ranking of control technologies are needed.

Flare Design and Proper Operation
The design of the IG flares is specific for the process stream that will be controlled and will result in high combustion efficiency. Proper operation of the flares will be implemented through the following Flare Best Practices:

1. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.
2. Flares shall be operated with a flame present at all times.
3. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

Process flaring minimization practices (Flare Minimization Plan)
Because the Acid Gas Flare is expected to be used in upset, malfunction and emergency conditions only, measures that might apply to flaring during normal start up and shutdown do not apply. Instead, the Flare Minimization Plan to reduce emissions will logically address the conduct of a root cause analysis and the consideration of corrective actions whenever flaring occurs. Therefore, the measure would be for the permittee to investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures would be implemented and documented.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Flare (EU-002)**	**10,400 T dry coal/day**	**None**	**Flare Design/Ops: Flare Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	002 Acid Gas Flare *	9, 413 T coke/day	None	Good Design and monitoring to ensure the presence of a flame at the flare tip at all the time.
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,722 T coal per day	None	Flare minimization plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	630 MW	None	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

The acid gas flare will generate very little CO because the acid gas will contain less than 1%v COS, CO, and hydrocarbons. Small amounts of CO will be produced from partial combustion of COS and hydrocarbons. Most of the CO in the acid gas will be combusted to CO_2. Flares are inherently efficient at combustion and the amount of CO emitted will primarily depend on the amount and duration of the acid gases flared.

Proposal: **Indiana Gasification, LLC – Rockport, IN**

Process flaring minimization practices

IG proposes the following as BACT from the Acid Gas Flare vent for CO:

(1) The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(2) Comply with the following flare best practices:

A. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

B. Flares shall be operated with a flame present at all times.

C. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Acid Gas Flare (EU-002).

(1) The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

(2) Comply with the following flare best practices:

A. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any 2 consecutive hours.

B. Flares shall be operated with a flame present at all times.

C. Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

Sulfur Dioxide (SO_2) BACT - Acid Gas Flare (EU-002)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare SO_2 emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

Add-on SO_2 controls that may be used on other types of sources, such as scrubbers, are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and proper operation – Flare design and monitoring are key elements in the emissions performance of flares. However, SO_2 emissions are merely a function of the amount of sulfur compounds in the gases vented to the flare and are unrelated to flare design. Therefore, for SO_2 purposes, flare design is not considered further.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare design and proper operation is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Process flaring minimization practices (Flare Minimization Plan)
To the extent actions can be taken to minimize the volume of gas going to the flare, whatever its sulfur content, emissions of SO_2 will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of process flaring minimization practices is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the IG facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the Acid Gas Flare will be extremely infrequent. No non-emergency flaring is anticipated.

(2) Another issue is that during most upset scenarios of the IG acid gas flares, the WSA itself (the normal disposition of the acid gas) is likely either in the process of being started up, in an upset, or otherwise not ready to receive the acid gases.

(3) Given the extremely infrequent nature of acid gas flaring, and given the likely lack of a reasonably compatible outlet for recovered gases at the time of acid gas flaring events, flare gas recovery is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare Gas Recovery is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies for flares are:

(1) Process flaring minimization practices (Flare Minimization Plan)

Because the Acid Gas Flare is expected to be used in upset, malfunction and emergency conditions only, measures that might apply to flaring during normal start up and shutdown do not apply. Instead, the Flare Minimization Plan to reduce SO2 emissions will logically address the conduct of a root cause analysis and the consideration of corrective actions whenever flaring occurs. Therefore, the measure would be for the permittee to investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures would be implemented and documented.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Flare (EU-002)**	**10,400 T dry coal/day**	**None**	**Flare Minimization Plan**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	002 Acid Gas Flare *	9, 413 T coke/day	None	No control
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,722 T coal per day	None	Flare minimization plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	630 MW	None	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Proposal: **Indiana Gasification, LLC** – Rockport, IN

Process flaring minimization practices

The Source is proposing the following as BACT from the Acid Gas Flare vents for SO_2:

> The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for Acid Gas Flare (EU-002).

The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the "root cause" of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Nitrogen Oxide (NO_X) BACT - Acid Gas Flare (EU-002)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare NOx emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

Certain NO_x controls that may be used on other types of sources, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and flue gas recirculation (FGR) are not applicable to flares because the outlet exhaust of an elevated process flare is not enclosed or contained. Therefore, the emissions or flue gases cannot be routed to an add-on control device, and such add-on controls have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and proper operation – Flare design and monitoring are key elements in emissions performance of flares. However, NOx emissions are not greatly affected by flare design. Instead, flare NOx is primarily a function of the amount of material flared and its nitrogen content. The open-flame nature of a flare results in inherently good NOx performance and prohibits the use of design features used on conventional low NOx or ultra low NOx gas burners in heaters and boilers. There are no flare burner tips available for low NOx performance on a high volume emergency flare.

The source is proposing the use of elevated flares. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented gases. A potential alternative flare design is an enclosed or ground flare. However, enclosed flares are not typically considered for high flow rate situations. An evaluation of typical enclosed flare designs indicates that the commercial designs that have been demonstrated are for landfill gas (low flow rates and low heating value) and upstream oil and gas operations (low flow rates and high heating values). These flare designs and controls are not technically feasible for this high gas flow, lower heating value application.

Therefore, no flare design or operational features were identified as applicable for NOx control. Therefore, these flare designs and controls are not technically feasible for this, high gas flow, lower heating value application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flare design and proper operation is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Process flaring minimization practices (Flare Minimization Plan)

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NOx will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Process flaring minimization practices is a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Flare gas recovery

Flare gas recovery – Flare gas recovery has been implemented at certain types of facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, acid gas flare gas recovery for this facility is not feasible for the following reasons.

(1) First, unlike a refinery’s nearly continuous supply of flared gases, flaring at the Acid Gas Flare will be extremely infrequent. No non-emergency flaring is anticipated.

(2) Another issue is that during most upset scenarios of the IG acid gas flares, the WSA itself (the normal disposition of the acid gas) is likely either in the process of being started up, in an upset, or otherwise not ready to receive the acid gases.

(3) Given the extremely infrequent nature of acid gas flaring, and given the likely lack of a reasonably compatible outlet for recovered gases at the time of acid gas flaring events, flare gas recovery is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flare gas recovery practices is not a technically feasible option for the Acid Gas Flare (EU-002) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Process flaring minimization practices (Flare Minimization Plan)

Because the Acid Gas Flare is expected to be used in upset, malfunction and emergency conditions only, measures that might apply to flaring during normal start up and shutdown do not apply. Instead, the Flare Minimization Plan to reduce emissions will logically address the conduct of a root cause analysis and the consideration of corrective actions whenever flaring occurs. Therefore, the measure would be for the permittee to investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures would be implemented and documented.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Flare (EU-002)**	**10,400 T coal/day**	**None**	**Process Flaring Minimization Practices**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	002 Acid Gas Flare *	9, 413 T coke/day	None	No control
28.0701-PSD	Hyperion Energy	08/20/2009	Flare *	400,000 bbl/day	None	Written Flare minimization plan, compliance with 40 CFR 60.18
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Flare *	13,722 T coal per day	None	Flare Minimization Plan,
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Flare *	630 MW	None	Must be operated with a flame present at all time

NOTE: * These emission units have not been built yet.

Proposal: **Indiana Gasification, LLC** – Rockport, IN

Process flaring minimization practices
The source is proposing the following as BACT from the Acid Gas Flare vent for NOx:

The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Acid Gas Flare (EU-002).

The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events. The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Auxiliary Boilers (EU-005 A and B)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. The available technologies include:

(1) Cyclones;

(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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:
One or more alternate methods of control may be considered when they are more cost-effective than add-on controls or when add-on control technology may not be feasible. For this source, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel; and

(2) Good Combustion Practices / Combustion Controls.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**
Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Since the concentration of PM/PM_{10} in the Auxiliary Boilers exhaust is very low (~0.005 gr/cf), a cyclone would not be effective at this source.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the cyclone is not a technically feasible option for the Auxiliary Boilers (EU-005A/B) at this source.

(b) **Wet Scrubber**
Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. Wet scrubbing towers are not typically used for fine particulate applications because high liquid to gas ratios are required, and typical pollutant loadings are 250-10,000 ppmv. *(EPA-452/F-03-016, Air Pollution Control Technology Fact Sheet for Spray Tower Wet Scrubber).* For fine particulate control, a venturi scrubber can be

used but typical loadings for such a scrubber are 0.1-50 grains/scf *(EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber).* Since the concentration of this stream (0.005 gr/cf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the wet scrubber is not a technically feasible option for the Auxiliary Boilers (EU-005A/B) at this source.

(c) **Electrostatic Precipitators**

An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Since the pollutant concentration of the Auxiliary Boilers exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the electrostatic precipitator is not a technically feasible option for the Auxiliary Boilers (EU-005A/B) at this source.

(d) **Fabric Filter Dust Collectors (Baghouse)**

A baghouse uses a fabric filter to capture particles as the gas stream flow through the fabric. Typical baghouse outlet design concentration is 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. Since the emission concentration from this source is already extremely low, a baghouse would not be effective in providing further particulate control. Therefore, a baghouse is rejected as an ineffective and not technically feasible control device for this source.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the fabric filter dust collector is not a technically feasible option for the Auxiliary Boilers (EU-005A/B) at this source.

(e) **Fuel Specifications – Clean Burning Fuel:** Clean burning natural gas and SNG have a very low potential for generating PM, PM_{10} and $PM_{2.5}$ emissions.

(f) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the Auxiliary Boilers to keep them in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the Auxiliary Boilers (EU-005A/B).

(1) Fuel Specifications – Clean Burning Fuel

(2) Good Combustion Practices / Combustion Controls

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination for IG along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Auxiliary Boiler (EU-005A/B)**	408 MMBtu/hr	0.0075 lb/MMBtu (filterable and condensable)	**Use of clean burning gaseous fuel**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Auxiliary Boiler *	938.30MM Btu/hour	6.99 pounds per hour	Good design and proper operation
2001-205-CM1 PSD	Energetix Lawton Energy Cogen Facility	12/12/2006	Auxiliary Boiler *	None	None	None
07-00534	Biomass Energy South Point Biomass Generation	04/04/2006	Auxiliary Boiler *	247 MMBtu/Hr	0.007 lb/MMBtu	None
PSD TX - 943	Corpus Christi Energy Center	02/04/2000	(3) Auxiliary Boilers 1-3, AB1-3 *	315 MMBtu/Hr	0.005 lb/MMBtu (filterable)	None
97019	Grays Ferry Cogen Partnership	03/21/2001	Auxiliary Boiler **,** Natural Gas*	1119 MMBtu/Hr	0.005 lb/MMBtu (filterable)	Good Combustion Practices

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers result only from fuel combustion (natural gas or SNG). Total PM/PM_{10} emissions from the boilers are estimated to be 5.62 tons/yr with the particulate concentration in the exhaust of only about 0.005 grains/dscf. This low concentration renders add-on controls infeasible as described below.

Generally add-on controls for PM, PM_{10} and $PM_{2.5}$ are not applied to a combustion source firing only clean gaseous fuel. This is because the PM, PM_{10} and $PM_{2.5}$ emissions are already extremely low (~0.005 gr/dscf), and are below levels that would be feasible for effective use of conventional particulate control devices (which are used on solid fuel fired combustion devices or other large particulate sources.)

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate control technologies for PM/ PM_{10}/$PM_{2.5}$ emissions from gas-fired boilers. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM_{10} and $PM_{2.5}$) emissions and add-on controls are not feasible. Gas fired sources have expected emissions of 0.0075 lb/MMBtu PM, PM_{10} and $PM_{2.5}$ (based on the AP-42 emission factor of 7.6 lb/MMscf for natural gas). The Corpus Christi Energy Center and Grays Ferry Cogen Partnership have BACT limits that appear lower but these limits are on the emissions of filterable PM only. AP-42 filterable PM is at this level, so these figures are consistent with the IG proposal.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Auxiliary Boilers (EU-005A/B).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0075 lb per MMBtu, each through the use of natural gas or SNG.

Carbon Monoxide (CO) BACT – Auxiliary Boilers (EU-005 A and B)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. CO control technologies include:

(a) Regenerative thermal oxidation;

(b) Catalytic oxidation;

(c) Flares

(d) Combustion Control

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (It is the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control.

Regenerative Thermal Oxidizer consists of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Auxiliary Boilers at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation.

For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO2 to SO3 and subsequent combination with moisture in the exhaust gas. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for gas fired units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Auxiliary Boilers at this source.

Flare

The low heating value of the Auxiliary Boiler exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is a technically infeasible option for the Auxiliary Boilers at this source.

Combustion Control

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. Combustion control is a technically feasible control option for the Auxiliary Boilers.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Regenerative Thermal Oxidizer - 99 % destruction efficiency

(2) Oxidation Catalyst - 75 % destruction efficiency

(3) Combustion Control

CO emissions are generally controlled by good combustion practices (GCP). Therefore, the source has proposed good combustion practices as the BACT for the CO emissions of these boilers.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Auxiliary Boiler (EU-005A/B)**	408 MMBtu/hr	0.036 lb/MMBtu based on 3 - hour average	**Good Combustion Practices**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Auxiliary Boiler *	938.30MM Btu/hour	33.78 pounds per hour	Good design and proper operation
2001-205-CM1 PSD	Energetix Lawton Energy Cogen Facility	12/12/2006	Auxiliary Boiler *	None	None	None
07-00534	Biomass Energy South Point Biomass Generation	04/04/2006	Auxiliary Boiler *	247 MMBtu/Hr	0.11 lb/MMBtu	None
PSD TX - 943	Corpus Christi Energy Center	02/04/2000	(3) Auxiliary Boilers 1-3, AB1-3 *	315 MMBtu/Hr	0.09 lb/MMBtu	None
97019	Grays Ferry Cogen Partnership	03/21/2001	Auxiliary Boiler **,** Natural Gas*	1119 MMBtu/Hr	0.04 lb/MMBtu	Good Combustion Practices

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

Carbon monoxide emissions from boilers are the result of incomplete fuel combustion. A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice and engineering design for gas-fired boilers is the best control for CO emissions. Natural gas (or SNG) combustion is already so efficient that add-on oxidation controls for such sources are not feasible (not to mention the limited-use nature of the IG boilers).

It is theoretically possible that further CO reductions could be achieved with an add-on thermal or catalytic oxidizer. However, any add-on oxidation control technology would not be cost effective since the CO concentration in this stream is already low. A rough perspective of costs for an add-on oxidizer can be obtained using cost ranges from US EPA's Air Pollution Control Technology

Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021). It lists the range of annualized cost of a regenerative thermal oxidizer as $8 - $33 per cfm and a regenerative catalytic oxidizer as $11 to $41 per cfm. Since the Auxiliary Boilers have a large exhaust flow rate (although low concentration of CO), we have conservatively assumed that the use of an oxidizer might have a cost at the lowest cost per cfm presented in this range ($8/cfm). Based on the emissions rate of about 27 tons/yr CO and an exhaust flow rate of 280,000 cfm, the cost-effectiveness of further controlling CO with an add-on oxidizer is conservatively estimated to be at least $80,000/ton. This clearly exceeds BACT for this type of CO source.

Costs Effectiveness for use of RTO on Auxiliary Boiler Exhaust

Control Alternative	CO Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton CO	Other Impacts
RTO	0.27	26.73	$9,800,000	$1,120,000	$2,240,000	$83,800	Additional energy use & CO Emissions
Baseline	27.0	(proposed)					

Note: Source exhaust (cfm) = 280000
Thermal Oxidation Costs based on lower - range costs for control from USEPA fact sheet for regenerative Thermal Oxidizer (EPA-452/F-03-021)
$35.0 capital cost $/cfm
$4.0 operating cost $/cfm
$8.0 Annualized $/cfm
99% Control efficiency for CO (Assumed)

In addition, the use of a thermal or catalytic oxidizer for CO control would require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (particularly NO_x) which will at least partially offset any benefits of additional CO control.

Therefore, BACT for this source for CO is proposed to be good engineering design of the boilers at 0.036 lb/MMBtu (based on vendor provided data of boiler operation using natural gas or SNG). This emissions performance is consistent with the lowest CO emission rates from any gas fired boilers found in the RBLC of this size regardless of operating rates.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Auxiliary Boilers (EU-005A/B).

The CO emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.036 lb/MMBtu based on a 3 - hour average through the use of good combustion practices.

Sulfur Dioxide (SO_2) BACT - Auxiliary Boilers (EU-005 A and B)

Step 1: Identify Potential Control Technologies

Emissions of Sulfur dioxide (SO2) from Auxiliary Boilers are generally controlled by;

1. Flue Gas Desulfurization

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing SO_2 emissions from the Auxiliary Boilers.

Flue Gas Desulfurization (FGD) System (Wet or Dry Scrubber)
A flue gas desulfurization system (FGD) is comprised either of a spray dryer that uses lime as a reagent followed by particulate control or a wet scrubber that uses limestone as a reagent. FGD is an established technology. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2. FGD systems are listed in the RBLC as BACT for sources higher concentrations of SO_2 emissions. Even though the SO_2 concentrations in the exhaust gases are very low, and the airflow volume is large, the scrubbing systems are technically feasible. Wet scrubbing FGD system is considerably cheaper than dry scrubbing.

Caustic scrubbing system that controls emissions by 90% at a higher inlet concentration is a proven system which operates at or below 2500°F.

Add-on SO_2 controls such as flue gas desulfurization described above, a common control in coal combustion, is not feasible for further control of SO_2 emissions because of inherently low SO_2 emissions from a clean gas fired boiler.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flue gas desulfurization system (FGD) is not a technically feasible option for the Auxiliary Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the SO_2 emissions resulting from the Auxiliary Boilers.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Auxiliary Boiler (EU-005A/B)**	408 MMBtu/hr	0.0006 lbs/MMBtu	**Use of natural gas or SNG**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Auxiliary Boiler *	938.30MM Btu/hour	0.28 pounds per hour	Fueled by natural gas or substitute natural gas (SNG)
2001-205-CM1 PSD	Energetix Lawton Energy Cogen Facility	12/12/2006	Auxiliary Boiler *	None	None	None
07-00534	Biomass Energy South Point Biomass	04/04/2006	Auxiliary Boiler *	247 MMBtu/Hr	0.60 lb/MMscf	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	Generation					
PSD TX - 943	Corpus Christi Energy Center	02/04/2000	(3) Auxiliary Boilers 1-3, AB1-3 *	315 MMBtu/Hr	0.093 lb/MMBtu	Fuel sulfur content limits
97019	Grays Ferry Cogen Partnership	03/21/2001	Auxiliary Boiler , Natural Gas*	1119 MMBtu/Hr	0.008 lb/MMBtu	Good Combustion Practices, low sulfur fuel

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for Auxiliary Boilers (EU-005A/B).

The SO_2 emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0006 lb/MMBtu and shall use only natural gas or SNG.

Nitrogen Oxide (NO_X) BACT - Auxiliary Boilers (EU-005 A and B)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR)

(c) Flue Gas Recirculation (FGR)

(d) Low NOx Burner (LNB)

(e) Low NOx Burner with Flue Gas Recirculation (LNB/FGR) or Ultra Low NOx Burner (UNLB)

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to N_2 and water. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through; above the optimum range, ammonia will oxidize to form additional NO_x. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is a technically feasible option for the Auxiliary Boilers at this source.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window. Given the standby nature of the operation of these boilers steady operating conditions cannot be expected.

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Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Auxiliary Boilers at this source.

Low NOx Burner (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a low NOx burner is a technically feasible option for the Auxiliary Boilers at this source.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flue Gas Recirculation (FGR) is a technically feasible option for the Auxiliary Boilers at this source.

FGR and LNB Combined
LNB and FGR can be used in combination to achieve a higher overall emissions reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of FGR with LNB is a technically feasible option for the Auxiliary Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Selective Catalytic Reduction — (up to 90% NOx Reduction)

(2) Low NOx Burner with Flue Gas Recirculation (LNB/FGR)-- (55% — 60% NOx Reduction)

(3) Low NOx Burner (LNB) — (40% — 50% NOx Reduction)

(4) Flue Gas Recirculation (FGR) — (25% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Auxiliary Boiler (EU-005A/B)**	408 MMBtu/hr	0.0125 lb/MMBtu based on 24-hr block daily average basis	**Ultra Low NOx Burner with FGR**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Auxiliary Boiler *	938.30MM Btu/hour	0.035 lb/MMBtu	Ultra low NOx Burners or SCR
2001-205-CM1 PSD	Energetix Lawton Energy Cogen Facility	12/12/2006	Auxiliary Boiler *	None	0.036 lb/MMBtu	Dry - low NOx Burners
07-00534	Biomass Energy South Point Biomass Generation	04/04/2006	Auxiliary Boiler *	247 MMBtu/Hr	0.06 lb/MMBtu	Using Natural Gas
PSD TX - 943	Corpus Christi Energy Center	02/04/2000	(3) Auxiliary Boilers 1-3, AB1-3 *	315 MMBtu/Hr	0.06 lb/MMBtu	None
97019	Grays Ferry Cogen Partnership	03/21/2001	Auxiliary Boiler **,** Natural Gas*	1119 MMBtu/Hr	0.10 lb/MMBtu	Low NOx Burners

Compliance determination is unknown for all these sources.

NOTE: * These emission units have not been built yet.

The following table summarizes the estimated cost and emissions reduction benefit for installing SCR on these boilers. The estimated cost-effectiveness shown below of more than $80,000/ton NOx reduced is too high to be considered reasonable. Consequently, SCR is rejected as BACT.

SCR Costs Analysis for IG Auxiliary Boilers
(Cost/Benefit Total for both Boilers)

Control Alternative	Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost/yr $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton NOx	Other Impacts
SCR	4.96	3.97	$1,468,000	$115,700	$321,300	$80,900	Insignif. Ammonia Emissions
ULNB/FGR	8.94	(proposed)					

Note: SCR costs shown are further detailed in Appendix C.

NSPS Subpart Db requires these boilers to achieve NO_x performance of at least 0.1 lb NO_x/MMBtu. A review of the RBLC for limited-use auxiliary boilers indicates the use of Low-NO_x (LNB) or Ultra Low NOx burners (ULNB) with NOx performance ranging from 0.035 to 0.10 lb NO_x/MMBtu. No further controls are indicated in the RBLC for limited-use auxiliary boilers.

Standard low NOx burners for the proposed boilers would achieve approximately 0.035 lb/MMBtu. This level of performance is consistent with BACT determination for other similar boilers – and should be sufficient as BACT. However, Indiana Gasification proposes to go beyond BACT by using Ultra Low-NOx burners with Flue Gas Recirculation (ULNB/FGR) capable of achieving 0.0125 lb/MMBtu. This level is one eighth the applicable NSPS standard and is better than the limits set for other auxiliary boilers. This is also the lowest NO_x emissions rate for any recently permitted boilers of this size regardless of operating rates.

Even further reduction of NOx is possible using selective catalytic reduction (SCR) which can be designed to reduce NOx to approximately 0.0069 lb/MMBtu (5 ppm in the exhaust). SCR is sometimes specified as BACT for very large heaters where the economies of scale help justify the costs. However, SCR is not cost effective for the auxiliary boilers, in part because the boilers will only have an annual utilization of 20% or less (decreasing the emissions reduction value of SCR). There is also a technical difficulty associated with SCR use for this boiler. In auxiliary service the boiler will need to ramp up and shutdown quickly and SCR performance will be compromised during those significant swings in load.

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for NOx from the proposed Auxiliary Boilers (EU-005):

Based on this analysis, BACT for the auxiliary boilers is proposed to be NO_x emissions performance of 0.0125 lb/MMBtu to be assessed on a 24-hr block daily average basis. . IG anticipates using ULNB with FGR to achieve this level. The NO_x emissions rate will be demonstrated with a continuous emissions monitor installed for NSPS Db.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Auxiliary Boilers (EU-005A/B).

The NOx emissions from the Auxiliary Boilers (EU-005A/B) operation shall not exceed 0.0125 lb/MMBtu based on a 24-hour block daily average basis and shall use Ultra Low NOx burners with FGR.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Regenerative Thermal Oxidizer (RTO) on the Acid Gas Removal Unit Vents (AGR) (EU-007A and B)

The acid gas removal (AGR) units remove CO_2 from the syngas and it will normally be compressed to a liquid and sold. Whenever it is instead vented, it will be sent to one of two Regenerative Thermal Oxidizers (RTOs), one serving each AGR. The RTOs will oxidize small amounts of CO, COS, methane and VOCs (methanol) in the vent gas. Because the heating value of the CO_2 stream to be vented is very low (it contains mostly non-combustible CO_2), a supplemental fuel is required to maintain the RTO at its operating temperature. As such, the RTO is both a control device and a source of emissions.

Although their emissions are combined out the same vent point, a separate BACT analysis has been prepared for the RTO and the AGR. The BACT analysis for the RTO addresses SO_2, NOx and PM from this vent, none of which are present in the AGR vent upstream of the RTO. The RTO BACT also addresses GHG emissions. The separate BACT analysis for the AGR vent also covers GHG's, addresses CO and includes a non-PSD State-only VOC BACT analysis. The AGR vent stream upstream of the RTO is responsible for the vast majority. A separate BACT analysis for the AGR is not presented for SO_2, NOx or PM, none of which are present in this stream upstream of RTO.

Step 1: Identify Potential Control Technologies

The particulate matter emissions from the AGR vent result from the fuel combustion in the regenerative thermal oxidizer (RTO). The use of clean burning natural gas or SNG will minimize these emissions.

From some processes, emissions of particulate matter (PM) and particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and $PM_{2.5}$ are controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Cyclones;

(2) Wet Scrubber;

(3) Electrostatic Precipitators (ESP);

(4) Fabric Filter Dust Collectors (Baghouses); and

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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:

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 IG Plant, the following alternate control methods were evaluated:

(1) Fuel Specifications – Clean Burning Fuel; and

(2) Good Combustion Practices / Combustion Controls.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclone**

Cyclones mechanically separate particulates through centrifugal and inertial forces, by forcing a particulate-laden stream to change direction, with the particles falling out as they hit the walls of a typically cone-shaped cyclone. Cyclones are used in applications with waste gas pollutant loadings of 1 – 100 gr/scf. Since the concentration of PM/PM_{10} in the RTO vent stream is very low (~0.001 gr/acf), a cyclone would not be effective in this plant.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the cyclone is not a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source.

(b) **Wet Scrubber**

Wet scrubbers use a flow or spray of liquid in a tower to contact a particulate-laden exhaust gas stream and absorb particles in the liquid, either physically, or in combination with a chemical reaction. Wet scrubbing towers are not typically used for fine particulate applications because high liquid to gas ratios are required, and typical pollutant loadings are 250-10,000 ppmv. *(EPA-452/F-03-016, Air Pollution Control Technology Fact Sheet for Spray Tower Wet Scrubber).* For fine particulate control, a venturi scrubber can be used but typical loadings for such a scrubber are 0.1-50 grains/scf *(EPA-452/F-03-017, Air Pollution Control Technology Fact Sheet for Venturi Scrubber).* Since the concentration of this stream (0.001 gr/acf) is already orders of magnitude lower, a wet scrubber would not achieve any appreciable particulate control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the wet scrubber is not a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source.

(c) **Electrostatic Precipitators (ESP)**

An electrostatic precipitator is a particulate control device that uses electrical forces to move particles entrained in an exhaust stream onto collector plates. The design inlet pollutant loadings for an ESP typically range from 0.5 – 50 gr/ft^3. Since the pollutant concentration on this stream is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the electrostatic precipitator is not a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source.

(d) **Fabric Filter Dust Collectors (Baghouses)**

A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. Typical baghouse outlet design concentration is 0.005 gr/scf. Since the emission concentration from this source is already less than this level, a baghouse would not be effective in providing further particulate control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the fabric filter dust collector is not a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source.

(e) **Fuel Specifications – Clean Burning Fuel:** Clean burning natural gas or SNG fuel such as syngas and natural gas have a very low potential for generating PM/PM10/PM2.5 emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM, PM_{10} and $PM_{2.5}$ emissions from the Acid Gas Removal Unit RTO Vents (EU-007A/B).

(f) **Good Combustion Practices / Combustion Controls:** Good combustion practices as well as operation and maintenance of the Acid Gas Removal Unit Vents to keep them in good working order per the manufacturer's specifications will minimize PM, PM_{10} and $PM_{2.5}$ emissions. This technology is technically feasible and will be ranked for evaluation as BACT for controlling PM emissions from Acid Gas Removal Unit Vents.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of the AGR Regenerative Thermal Oxidizer (EU-007A/B).

(1) Fuel Specifications – Clean Burning Fuel

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Removal Unit Vents (EU-007A/B)**	**10,400 T dry coal/day**	**0.58 pounds per hour**	**Use of clean burning gaseous fuel, Good Combustion Practices**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Acid Gas Recovery Vents *	9,413 T/D	0.36 lb/MMBtu and 0.3 lb/hr	None
Permit V-09-006	Cash Creek Gasification	05/05/2010	Acid Gas Recovery Vents *	770 MW	None	None
28.0701-PSD	Hyperion Energy	08/20/2009	Acid Gas Recovery Vents *	400,000 bbl/day	11.2 lb/hour, 0.13 lb/long T S loaded	None
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Acid Gas Recovery Vents *	13,722 T coal per day	0.5 pounds per hr and	None

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
					1.9 tpy	
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Acid Gas Recovery Vents *	630 MW	0.0075 lb/MMBtu	None

NOTE: * These emission units have not been built yet.

The PM, PM_{10} and $PM_{2.5}$ emissions from the AGR vent result from the supplemental fuel combustion (natural gas or SNG) in the Regenerative Thermal Oxidizer (RTO) that is used to control CO, H_2S, COS and methanol in the AGR unit vent stream. The vented material (upstream of the RTO) contains no PM/PM_{10}. The RTO itself has inherently low PM/PM_{10} emissions due to the use of only clean fuel in the RTO. In addition, the use of an RTO rather than a conventional Thermal Oxidizer further limits PM/PM_{10} emissions because it recovers heat and preheats the exhaust before it enters the combustion chamber. In this way it lessens the amount of supplemental fuel fired.

No add-on controls for PM, PM_{10} and $PM_{2.5}$ have ever been applied to a similar RTO or other gas-only fired combustion source. The lack of post-combustion controls on an RTO is due to the fact that emissions are already at extremely low concentrations (~0.001 gr/acf), and, therefore, they are below levels that would be feasible using conventional particulate control devices that are normally used on solid fuel fired combustion devices or other large particulate sources.

Only one similar source was located in the RBLC (Lake Charles Gasification), however, the above comparison also includes the recently permitted and similar SNG facilities. The table shows their recently permitted PM, PM_{10} and $PM_{2.5}$ limits. The emission rates for PM, PM_{10} and $PM_{2.5}$ are comparable to other permitted emission of these similar facilities.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for AGR Regenerative Thermal Oxidizer (EU-007A/B).

The PM, PM_{10} and $PM_{2.5}$ emissions from the AGR Regenerative Thermal Oxidizer (EU-007A/B) operation shall not exceed 0.29 pounds per hour, each, through the use of clean burning gaseous fuel and good combustion practices.

Carbon Monoxide (CO) BACT - AGR Regenerative Thermal Oxidizer (EU-007A and B)

The carbon monoxide emissions from the AGR vent result primarily from the CO in the AGR vent stream. Only a very small portion of the CO emissions come from supplemental fuel combustion in the RTO, which uses clean burning natural gas or SNG. Carbon Monoxide BACT for this stream is discussed under the Acid Gas Recovery Vent BACT analysis.

Sulfur Dioxide (SO_2) BACT - AGR Regenerative Thermal Oxidizer (EU-007A and B)

The acid gas removal (AGR) units remove CO_2 from the syngas and it will normally be compressed to a liquid and sold. Whenever it is instead vented, it will be sent to one of two Regenerative Thermal Oxidizers (RTOs), one serving each AGR. The AGR vent stream upstream of the RTO does not contain SO_2, but the RTOs will oxidize small amounts of COS and H_2S in the vent gas. The sulfur dioxide emissions from the AGR vent result almost entirely from the oxidation of the sulfur that was in the AGR vent stream. Because the heating value of the CO_2 stream to be vented is very low, supplemental natural gas or NSG fuel will be used and will also contribute a very small amount of SO_2 to the emissions. However, less than 1% of the total SO_2 in this vent comes from the supplemental fuel.

Step 1: Identify Potential Control Technologies

Emissions of sulfur dioxide (SO_2) from this vent are primarily controlled by the inherent efficient design of the Rectisol acid gas removal system which results in a CO_2 stream with very low sulfur content. The use of an add-on scrubber was also considered.

Step 2: Eliminate Technically Infeasible Options

Rectisol
The IG facility will use the Rectisol process for removal of acid gases (principally H_2S and COS) from the syngas stream and subsequent conversion to sulfuric acid product. SO_2 emissions from the AGR vent are a function of the effectiveness of the AGR system in separating these sulfur-bearing streams out of the syngas and out of the captured CO_2 stream.

Physical solvent systems such as Selexol and Rectisol provide the highest level of control for this type of source. The IG selected Rectisol system is considered to be as good or better at removing sulfur bearing compounds than Selexol. Less effective technologies include solvent scrubbing, such as amine systems.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Rectisol system is a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source

Scrubber
The SO_2 emissions from the AGR vent are at very low levels as a result of the inherent design of the Rectisol Acid Gas Removal (AGR) system which is very effective in absorbing sulfur compounds and separating them into the acid gas stream sent to the wet sulfuric acid unit. The small amount of residual sulfur contained in the AGR vent stream, in the form of H_2S and COS, is converted in the thermal oxidizer to SO_2 emissions. The SO_2 emitted at the AGR Vent corresponds to only about 2 ppmv. This is too low a level of emissions for further scrubbing to be effective, as described below. As a result, there is no feasible add-on control for SO_2 from the AGR.

The EPA Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurizatoin (FGD) - Wet, Spray Dry and Dry Scrubbers (EPA-452/F03-034) states that these scrubbers are typically only installed on coal- and oil-fired units, with an inlet pollutant loading of approximately 250 - 2000 ppm SO_2. In the very best cases, wet scrubbing systems reduce SO_2 to single digit ppm levels. However, the AGR vent is already 2 ppm SO_2 (because it is the product of an extremely effective sulfur scrubbing system – Rectisol). Because further exhaust gas sulfur scrubbing systems would not be effective or applicable as an add-on control in this service, scrubbing is not considered feasible for this source.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a scrubber is not a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The most effective method for control of SO_2 emissions resulting from operation of the Acid Gas Removal Unit Vents at this source is the use of a Rectisol to convert acid gases to sulfuric acid.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Removal Unit Vents (EU-007A/B)**	**10,400 T dry coal/day**	**6.33 pounds per hour based on 24 hour block daily average**	**Rectisol, Proper design of AGR and Limit on Sulfur to RTO**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Acid Gas Recovery Vents *	9,413 T/D	22.92 pounds per hour	Rec tisol
Permit V-09-006	Cash Creek Gasification	05/05/2010	Acid Gas Recovery Vents *	770 MW	43.2 pounds per hour	Selexol
28.0701-PSD	Hyperion Gasification - South Dakota	08/20/2009	Acid Gas Recovery Vents *	400,000 bbl/day	114.2pounds per hour	Rec tisol
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Acid Gas Recovery Vents *	13,722 T coal per day	11.0 pounds per hr and 48.3 tpy	Rec tisol
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Acid Gas Recovery Vents *	630 MW	19.86 pounds per hour	None

NOTE: * These emission units have not been built yet.

Proper design of the Rectisol Unit will keep the concentration of sulfur compounds in the CO_2 stream to the RTO to very low levels. The small residual sulfur in the AGR vent stream, in the form of H_2S and COS, is converted in the thermal oxidizer to SO_2 emissions. IG expects potential SO_2 emissions from the AGR vent of 6.33 lb/hr and 26.27 tpy (total for both AGR vents). The very low level of sulfur compounds expected in the AGR Vent corresponds to only about 2 ppmv SO_2 in the exhaust. This is too low for further scrubbing to be effective and there is no feasible add-on control for SO_2 from the AGR.

The proposed performance level for the IG facility compares very favorably with other facilities. The Rectisol unit at the IG facility has the lowest mass emission rate of SO_2 compared to the above similar permitted facilities. Given the relative size of each facility and the proposed SO_2 emission rate, IG is achieving the lowest SO_2 emission rate among similar facilities.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for Acid Gas Removal Unit Vents (EU-007A/B).

The SO_2 emissions shall be reduced by the use of a Rectisol process and the SO_2 emissions shall not exceed 3.17 pounds per hour for each Acid Gas Removal Unit Vent (EU-007A/B), based on a 3-hour average.

Nitrogen Oxide (NO_X) BACT - AGR Regenerative Thermal Oxidizer (EU-007A and B)

The acid gas removal (AGR) units remove CO_2 from the syngas and it will normally be compressed to a liquid and sold. Whenever it is instead vented, it will be sent to one of two Regenerative Thermal Oxidizers (RTOs), one serving each AGR. The RTOs will oxidize small amounts of CO, COS, methane and VOCs (methanol) in the vent gas. Because the heating value of the CO_2 stream to be vented is very low, a supplemental fuel is required to maintain the RTO at its operating temperature. As such, it is both a control device and a source of emissions.

The NOx emissions from the AGR vent result from the fuel combustion in the regenerative thermal oxidizer (RTO). Low NOx performance of the RTO is provided by use of a natural gas injection system.

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR)

(c) Flue Gas Recirculation (FGR)

(d) Low NOx Burner (LNB) or other combustion control designed for Low NOx performance.

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

Low NOx Combustion Controls
The NOx emissions from the AGR vent result from the supplemental fuel combustion (natural gas or SNG) in the Regenerative Thermal Oxidizer used to thermally destroy CO, organic and sulfur compounds in the vent stream. The vented material upstream of the RTO contains no NO_x. (NO_x emissions from supplemental fuel combustion are estimated to result in NO_x emissions equal to 0.05 lb NO_x/MMBtu which equates to 3.95 lbs/hr (total from both RTOs)).

The supplemental fuel combustion products from the RTO are reduced by the following techniques:

(1) **Use of a regenerative thermal oxidizer** – Using an RTO instead of other thermal oxidation devices reduces the supplemental fuel used for combustion by maximizing heat recovery.

(2) **Use of only clean burning natural gas or SNG fuel** – Inherently clean fuels.

(3) **Fuel injection into the RTO ceramic beds** - The ceramic bed will be above the auto-ignition temperature of natural gas. Designing the RTO to provide for the majority of the natural gas injection in these beds will allow natural gas combustion to occur at lower temperatures than in traditional burners thereby reducing the NO_x generated. (Note: Conventional NG burners are used to initially bring the RTO up to temperature.)The amount of NOx formed increases with the peak temperature and the duration of that peak temperature in the combustion process. Because there is a direct correlation between temperature of combustion and NO_x formation, this design reduces NOx emissions versus conventional regenerative thermal oxidizers

All three of the above techniques are technically feasible and reduce NO_x emissions.

Add-on Controls
Add-on controls for NO_x, such as SCR, SNCR and FGR are not feasible because the exhaust/vent stream is already extremely low in NO_x concentration and flow to the RTO will be intermittent. The combustion stream that exits the RTO is diluted with the high-volume process stream making the NO_x concentrations extremely dilute. NO_x emissions at the stack outlet will be less than 2 ppm. This low concentration and low total mass of NO_x emissions do not allow additional reductions through the use of any further add-on controls to be technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, the source has elected the use of a low NOx performance with natural gas injection for controlling the NOx emissions resulting from the Acid Gas Removal Unit Vents.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Removal Unit Vents (EU-007A/B)**	**10,400 T dry coal/day**	**3.95 pounds per hour based on 24 -hr block daily average**	**Low NOx Performance with natural gas injection system**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Acid Gas Recovery Vents *	9,413 T/D	2.89 pounds per hour	**No additional control**
Permit V-09-006	Cash Creek Gasification	05/05/2010	Acid Gas Recovery Vents *	770 MW	None	**None**
28.0701-PSD	Hyperion Gasification - South Dakota	08/20/2009	Acid Gas Recovery Vents *	400,000 bbl/day	0.06 lb/MMBtu and 6.1 pounds per	**Low NOx Burners**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
					hour	
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Acid Gas Recovery Vents *	13,722 T coal per day	2.7 pounds per hr and 11.7 tpy	**Good Operating Practices**
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Acid Gas Recovery Vents *	630 MW	None	None

NOTE: * These emission units have not been built yet.

Only one similar source was located in the RBLC (Lake Charles Gasification), however, the comparison also includes the recently permitted and similar SNG facilities. The table shows their recently permitted NO_x limits.

The emission rates for NOx are comparable to, or lower than, the lowest permitted emission of these similar facilities after accounting for difference in the sizes of the units.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Acid Gas Removal Unit Vents (EU-007A/B).

The NOx emissions from the Acid Gas Removal Unit Vents (EU-007A/B) shall be controlled by Low NOx Performance with natural gas injection and the NOx emissions shall not exceed 1.98 pounds per hour from each AGR/RTO unit based on a 3-hour average.

Carbon Monoxide (CO) BACT – Acid Gas Removal Unit Vents (EU-007A and B)

The AGR vent stream contains over 4000 lbs/hr of CO and will be routed through an RTO providing 99% control of the CO in the vented gases. The carbon monoxide emissions from the AGR vent result primarily from the 1% of uncontrolled CO in the AGR vent stream. Only a very small portion of the CO emissions come from supplemental fuel combustion in the RTO, which uses clean burning natural gas or SNG.

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by efficient oxidation. Possible combustion control technologies include:

(a) Regenerative Thermal oxidizer;

(b) Conventional Thermal oxidizer;

(c) Flare; and

(d) Catalytic Oxidation.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
Thermal oxidizers destroy air toxics and organic compounds that are discharged in industrial process exhausts. Thermal oxidizers achieve destruction through the process of high temperature thermal oxidation, converting combustible compounds to carbon dioxide and water

vapor, and oxidizing toxic compounds to non-toxic compounds. Some thermal oxidizers preheat the incoming air by capturing heat from the outgoing air stream to reduce operating costs. Regenerative thermal oxidizers use ceramic heat transfer beds to recover thermal energy from the oxidation process. The heat transfer beds act as heat exchangers. The heat recovery can be as much as 90 to 95%. Process gas enters the RTO through an inlet manifold. The gas is directed into an energy recovery chamber which preheats the process gas. The process gas and contaminants are progressively heated in the ceramic bed as they move toward the combustion chamber.

Thermal oxidation of CO to CO_2 is the most effective treatment for this AGR Vent stream prior to venting to the atmosphere. Thermal oxidation will also control other contaminants in this stream by converting methanol to CO_2 and water, H_2S to SO_2 and water and COS to SO_2 and CO_2. To achieve thermal oxidation, air must be added and the combined stream heated to approximately 1600 degrees F.

The heating value of the CO_2 stream to the RTO is very low because it contains mostly non-combustible CO_2 (98%). Consequently, each RTO will have a natural gas/SNG burner to raise the temperature in the combustion chamber of the RTO to 1600 degrees F. This ensures a high oxidation efficiency of the CO (99%), CH_3OH (99%), H_2S (98%), and COS (98%). Most of this heat is recovered by heating one of the heat transfer beds which will be used subsequently to preheat the incoming gas stream (i.e.; the two beds are alternated between incoming gas and exhaust gas.) This reduces the supplementary fuel firing rate and associated combustion emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer (RTO) is a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source.

Conventional Thermal oxidizer
A conventional thermal oxidizer would be technically feasible for this stream. The control efficiency of a conventional Thermal Oxidizer is the same as the Regenerative Thermal Oxidizer, and provides a 99% oxidation efficiency for CO and 98% oxidation efficiency of H_2S and COS. However, a Conventional Thermal Oxidizer does not provide for heat recovery.

There is very little heating value inherent in the AGR Vent stream which has an approximate concentration of 98%v CO_2. Consequently, a conventional Thermal Oxidizer without heat recovery would have a very high supplemental fuel requirement (more than 10 times higher than a regenerative TO) to reach a 1600 F gas temperature. Therefore, a conventional TO would have higher operating costs and much higher combustion pollutant emissions (NO_x, VOC, PM_{10}).

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a conventional thermal oxidizer is a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source

Flare
Although the pollutants (CO, methanol, H_2S, and COS) concentrations are low to very low, the stream flow rate is very high. The low heating value of the CO_2 stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is a technically infeasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source

Catalytic Oxidation
A catalytic oxidizer is an add-on control device to control VOC emissions by using a bed of catalyst that facilitates the oxidation of combustible gases. The catalyst increases the reaction rate and allows the conversion of VOC at lower temperature than a thermal incinerator. Typical problems encountered when using a catalytic incinerator is that the contaminants in the exhaust stream can poison or foul the catalyst bed.

A catalytic oxidizer converts the CO in the combustion gases to CO_2 at temperatures ranging from 500 degrees F to 700 degrees F in the presence of a catalyst. Catalytic oxidation is proposed for the Cash Creek Generation gasification AGR Vent Stream at a control level of at least 90%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for the Acid Gas Removal Unit Vents (EU-007A/B) at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling VOC emissions from these operations.

(1) Regenerative thermal oxidation (99 % CO Reduction)

(2) Conventional thermal oxidation (99 % CO Reduction)

(3) Catalytic oxidizer (over 90 % CO Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Acid Gas Removal Unit Vents (EU-007A/B)**	**10,400 T dry coal/day**	**48 pounds per hour based on 3 hour average, each**	**Regenerative Thermal Oxidizer**
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Acid Gas Recovery Vents *	9,413 T/D	43.97 pounds per hour Max	Regenerative Thermal Oxidizer
Permit V-09-006	Cash Creek Gasification	05/05/2010	Acid Gas Recovery Vents *	770 MW	126 pounds per hour	Catalytic Oxidizer

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
28.0701-PSD	Hyperion Energy	08/20/2009	Acid Gas Recovery Vents *	400,000 bbl/day	0.08 lb/MMBtu and 8.1 lb/hr	Thermal Oxidizer
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Acid Gas Recovery Vents *	13,722 T coal per day	61 pounds per hr and 266.2 tpy	Thermal Oxidizer
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Acid Gas Recovery Vents *	630 MW	0.08 lb/MMBtu	Thermal Oxidizer

NOTE: * These emission units have not been built yet.

A regenerative thermal oxidizer will provide the highest degree of control of CO for this source. It should be noted that there are a small amount of additional energy requirements and generated pollutants (NO_x and PM_{10}) through the supplemental fuel combustion from using a thermal control device. However, these impacts are lower with an RTO than with a conventional TO because the supplemental fuel demand is less.

The regenerative thermal oxidizer and the conventional thermal oxidation control options both provide the same level of performance regarding CO destruction efficiency (99% control). However, the RTO generates lower CO emissions due to the lower incremental fuel use than the conventional thermal oxidizer.

The oxidation efficiency of CO from both the Regenerative and Conventional Thermal Oxidizers are the same (99%). Overall CO emissions generated from the AGR Vent stream are higher from the Conventional Thermal Oxidizer since it would require significantly more supplemental fuel firing (over 500 MMBtu/hr). The extra CO from the additional fuel combustion will roughly double the emissions of CO. Thus, the regenerative thermal oxidizer will provide a superior CO control performance compared to the conventional thermal oxidizer. Likewise, a catalytic oxidizer would perform no better.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Acid Gas Removal Unit Vents (EU-007A/B).

The IDEM agrees that the CO BACT for Acid Gas Removal Unit Vents (EU-007A/B) shall be established as follows:

The CO emissions shall be controlled by a the use of regenerative thermal oxidizer (RTO) and the CO emissions shall not exceed 48 pounds per hour for the Acid Gas Removal Unit Vents (EU-007A/B), each, based on a 3-hour average.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Gasifier Preheat Burners (EU-008A-E)

Step 1: Identify Potential Control Technologies

PM, PM_{10} and $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. Generally, PM, PM_{10} and $PM_{2.5}$ 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.

Step 2: Eliminate Technically Infeasible Options

Add - on - Controls

The PM, PM_{10} and $PM_{2.5}$ emissions from this source result only from the small amount of natural gas or SNG that are used. These emissions are very low due to the clean fuel used and because the exhaust also passes through the water quench section of the gasifier where the quench water may serve to remove some of the PM. The resultant $PM/PM_{10}/PM_{2.5}$ emissions are less than 0.01 tons/yr per preheat burner. This emissions level is so low that it would not be feasible for any add-on controls such as cyclones, baghouses, ESPs or wet scrubbers to effectively further reduce emissions. Also, regardless of the emissions rate, because a steam eductor draws the exhaust out of the gasifier, the resultant very high moisture content of the exhaust would render the more effective of these controls – an ESP or baghouse – technically infeasible. For these reasons, the above-listed add-on particulate controls are not considered feasible in this BACT analysis. There is no evidence that any of these add-on controls have ever been used to control natural gas combustion particulate.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of add-on controls is not a technically feasible option for the Gasifier Preheater Burners at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the PM, PM_{10} and $PM_{2.5}$ emissions resulting from the Gasifier Preheater Burners (EU-008).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Gasifier Preheat Burners (EU-008A-E)**	**35 MMBtu/hr**	**0.0007 lb/MMBtu**	**Use of Clean burning gaseous fuel**
28.0701 - PSD	Hyperion Energy	8/20/2009	Gasifier Startup Burners*	400,000 bbl/day	None	No Control
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Gasifier Startup Preheat	9,413.0 T/D	0.01 lbs/hour, each	Good design and proper operation

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
			Burners (5)*			
9923 -AC010	TESORO ALASKA COMPANY - KENAI REFINERY	03/21/2000	#1 Preheat Startup Burners, H1102*	1.65 MMBtu/Hr	None	None Indicated
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Gasifier Startup Burners*	13,722 T coal per day	0.01 lb/MMBtu	None

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

(a) **Proposal**: **Indiana Gasification**, LLC – Rockport, IN
The following has been proposed as BACT for the PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be the use of clean burning gaseous fuel and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.0007 lb /MMBtu.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Gasifier Preheat Burners (EU-008A-E).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0007 lb /MMBtu and shall use only natural gas or SNG.

Carbon Monoxide (CO) BACT – Gasifier Preheat Burners (EU - 008A-E)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by combustion control. Oxidation in an add-on control is also an option in some cases. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares. The list of identified technologies includes:

(a) Regenerative thermal oxidation;

(b) Catalytic oxidation;

(c) Flares

(d) Combustion Control

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers

The thermal oxidizer is a high temperature process maintained by a combustion of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. As it is passing through the high temperature zone, the waste gas, containing CO is heated to its ignition temperature. The mixture continues to react as it flows through the combustion chamber.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal oxidizer units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

Regenerative Thermal Oxidizer is supplemented with direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed). The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical. Given the fact that these burners are used intermittently, are relatively small and vent through a wet quench, it is not feasible to operate them in combination with an RTO.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically infeasible option for the Gasifier Preheat Burners at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology. The waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate. Emissions from emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. Given the intermittent operation of these burners, their size and the use of a wet quench, catalytic oxidation is not likely to work in this application and it has never been used on this type of equipment.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically infeasible option for Gasifier Preheat Burners at this source.

Flare
Although the pollutants (CO, methanol, H_2S, and COS) concentrations are low to very low, the stream flow rate is very high. The low heating value of the CO_2 stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Flaring is normally applied to a gas stream that is capable of maintaining combustion. The exhaust from the preheat burners, is very low in CO and wet and cannot support combustion. Flares have not been utilized or demonstrated as a control device for CO from this type of gas fired combustion source.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is a technically infeasible option for the Gasifier Preheat Burners at this source.

Combustion Control
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. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only viable control for the control of CO emissions from the Gasifier Preheat Burners is a combustion control.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Gasifier Preheat Burners (EU-008A-E)**	**35 MMBtu/hr**	**0.056 lb CO /MMBtu**	**Good Combustion Practices**
28.0701 - PSD	Hyperion Energy	8/20/2009	Gasifier Startup Burners*	400,000 bbl/day	0.1 lb/MMBtu	No Control
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Gasifier Startup Preheat Burners (5)*	9,413.0 T/D	1.01 lb/hr	Good design and proper operation
9923 -AC010	TESORO ALASKA COMPANY - KENAI REFINERY	03/21/2000	#1 Preheat Startup Burners, H1102*	1.65 MMBtu/Hr	0.035 lb/MMBtu (Post -BACT limit)	None
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Gasifier Startup Burners*	13,722 T coal per day	0.1 lb/MMBtu	None

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

Proposal: **Indiana Gasification**, LLC – Rockport, IN

The following has been proposed as BACT for the CO emissions from the Gasifier Preheat Burners (EU-008A-E):

The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be limited to less than 0.056 lb CO/MMBtu through the use of good combustion practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Gasifier Preheat Burners (EU-008A-E).

The CO emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.056 lb CO/MMBtu and shall use good combustion practices.

Sulfur Dioxide (SO_2) BACT - Gasifier Preheat Burners (EU - 008A-E)

Step 1: Identify Potential Control Technologies

Emissions of Sulfur dioxide (SO_2) are generally controlled by the use of either;

1. Flue Gas Desulfurization

2. Low sulfur fuel

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E).

Low sulfur fuel
These burners are proposed to use only natural gas or SNG. As a low-sulfur fuel source, this will minimize SO_2 emissions.

Flue Gas Desulfurization (FGD) System (Wet or Dry Scrubber)
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2. FGD systems are listed in the RBLC as BACT for sources high in SO_2 emissions. Wet scrubbing FGD system is considerably cheaper than dry scrubbing.

Add-on SO_2 controls such as flue gas desulfurization described above, a common control in coal combustion, is not feasible for further control of SO_2 emissions because of inherently low SO_2 emissions from a clean gas fired operation.

The SO_2 emissions are inherently very low through the use of natural gas or SNG. Clean natural gas combustion exhaust contains less than 2 ppm $SO_{2.}$ This is too low for any add-on control technology such as a wet scrubber to be feasible. Wet scrubbing systems are typically only installed on exhaust streams of coal and oil fired units, with an inlet pollutant loading of approximately 250 - 2000 ppm SO_2. In the very best cases, wet scrubbing systems can achieve up to as high as 98% control and reduce SO_2 to single digit ppm levels. However, this vent is already less than 2 ppm SO_2 (because of the clean fuel used). Therefore, further exhaust gas sulfur scrubbing systems would not be effective or applicable as an add-on control in this service. Accordingly, FGD for SO_2 control was not considered feasible as BACT.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flue gas desulfurization system (FGD) is not a technically feasible option for the Gasifier Preheat Burners at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Low sulfur fuel

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Gasifier Preheat Burners (EU-008A-E)**	**35 MMBtu/hr**	**0.0006 lb/MMBtu**	**Use of Clean burning gaseous fuel**
28.0701 - PSD	Hyperion Energy	8/20/2009	Gasifier Startup Burners*	400,000 bbl/day	0.006 lb/MMBtu	No Control
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Gasifier Startup Preheat Burners (5)*	9,413.0 T/D	0.01 lb/hr	Natural gas
9923 -AC010	TESORO ALASKA COMPANY - KENAI REFINERY	03/21/2000	#1 Preheat Startup Burners, H1102*	1.65 MMBtu/Hr	None	None Indicated
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Gasifier Startup Burners*	13,722 T coal per day	0.0013 lb/MMBtu	None

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

(a) **Proposal**: **Indiana Gasification**, LLC – Rockport, IN

The following has been proposed as BACT for the SO2 emissions from the Gasifier Preheat Burners (EU-008A-E):

The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be Use of Clean burning gaseous fuel and the SO2 emissions shall not exceed 0.0006 lb SO2/MMBtu.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for Gasifier Flare (EU-008A-E).

The SO_2 emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.0006 lb SO_2/MMBtu and shall use natural gas or SNG.

Nitrogen Oxide (NO_X) BACT - Gasifier Preheat Burners (EU - 008A-E)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following techniques:

(a) Selective Catalytic Reduction (SCR)

(b) Flue Gas Recirculation (FGR)

(c) Low NOx Burner (LNB)

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and nitrogen (N_2). Under optimal conditions, SCR has removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

NOx add-on controls such as SCR would not be effective in this service because SCR requires a specific narrow operating temperature range (about 480°F to 800°F) to be effective. There is no location in the exhaust path of the gasifier preheat burners that has this required temperature range. The gasifier itself is operated much higher than this temperature (target temperature 2500°F). The preheat burner exhaust gases exit the hot gasifier through the quench section of the gasifier and through a steam eductor in route to the stack. The stack temperature is only about 232°F. Therefore, SCR is technically infeasible.

Besides the temperature incompatibility, SCR is not typically used on combustion sources smaller than about 250 MMBtu/hr because its high capital and operating costs are not justified. The preheat burners design capacity is only 35 MMBtu/hr and their average annual operating rate is much lower.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Gasifier Preheat Burner at this source.

Low NOx Burner (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air and fuel, as well as other methods that effectively lower the flame temperature.

The LNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a stage air combustion LNB, either air or fuel is added downstream of the primary combustion zone. Depending on which of this NOx reduction technique is used, LNBs with stage combustion are subdivided into staged air burners and staged fuel burners.

Low NOx designs are not feasible for the preheat burners due to the design of the burners and the extremely high gasifier temperature required (2500 F). The burners are designed similar to a lance, or fuel nozzle, and are only used during preheat. The burners fire into the gasifiers which do not include tubes or other heat absorbing material. This results in the temperature being much higher than many applications that incorporate low NO_x burner technology. The extreme desired operating temperature is above the temperature that nitrogen breaks apart making NO_x reduction not effective.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a low NOx burner is not a technically feasible option for the Gasifier Preheat Burner at this source.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR can lower NOx emissions on two ways;
The cooled, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reaction for one of the ingredients they need.

External flue gas recirculation is also not feasible because there is no way to return the flue gas to the burner. The burner is inserted and removed during each start up and cannot be connected to the flue exhaust. Additionally, the preheat burners have limited use and overall very low annual emissions are expected from each burner.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flue Gas Recirculation (FGR) is not a technically feasible option for the Gasifier Preheat Burner at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the NOx emissions resulting from the Gasifier Preheat Burners (EU-008A-E).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Gasifier Preheat Burners (EU-008A-E)**	**35 MMBtu/hr**	**0.10 lb NOx /MMBtu**	**Good Combustion Practices**
28.0701 - PSD	Hyperion Energy	8/20/2009	Gasifier Startup Burners*	400,000 bbl/day	0.07 lb/MMBtu	low NOx Burners

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Gasifier Startup Preheat Burners (5)*	9,413.0 T/D	1.80 lb/hr , each	Good Design and Proper Operation
9923 -AC010	TESORO ALASKA COMPANY - KENAI REFINERY	03/21/2000	#1 Preheat Startup Burners, H1102*	1.65 MMBtu/Hr	0.14 lb/MMBtu	None Indicated
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Gasifier Startup Burners*	13,722 T coal per day	0.2 lb/MMBtu	None

Compliance determination is unknown for all these sources.
NOTE: * These emission units have not been built yet.

IDEM notes that the emissions limit for the Hyperion Plant gasifier preheaters is somewhat lower than the limit proposed by IG. IG has indicated that communications with the burner vendors indicate that the lower number would be achievable during the time that a preheater is used to keep a gasifier in standby and this is the most frequent mode of burner operation. However, when the gasifier needs to be heated to 2500 deg F, just before startup, the emissions increase to the figure IG has proposed. IDEM has decided to recognize this difference and accept the IG proposal, as it covers the worst case mode.

(a) **Proposal**: **Indiana Gasification**, LLC – Rockport, IN

The following has been proposed as BACT for the NOx emissions from the Gasifier Preheat Burners (EU-008A-E):

The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall be good combustion practices and the NOx emissions shall not exceed 0.10 lb NOx /MMBtu.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Gasifier Preheat Burners (EU-008A-E).

The NOx emissions from the Gasifier Preheat Burners (EU-008A-E) operation shall not exceed 0.10 lb NOx /MMBtu and shall use good combustion practices.

NOx, CO, SO_2 and $PM/PM_{10}/PM_{2.5}$ BACT – Emergency Generators (EU-009A/B)

Step 1: Identify Potential Control Technologies

These generators are used in emergencies only and operate about 50 hours a year to ensure that they will start when needed. They will be designed to meet the applicable NSPS and NESHAP limited discussed below. Combustion design will be used by the manufacturer to meet those limits. These units will be operated on low sulfur diesel. Diesel has been chosen over natural gas and SNG for safety reasons. Should an incident affect the gas system, an independent source of fuel, in the form of a localized dedicated fuel tank, is available. Beyond the use of low sulfur diesel, which has beneficial impacts on both the SO_2 and particulate emissions of the unit, the emissions of Nitrogen oxide (NOx), CO, SO_2, PM, PM_{10} and $PM_{2.5}$ from emergency generators are not generally controlled.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing emissions from the Emergency Generators. No additional controls have been identified.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the NOx, CO, SO_2 PM, PM_{10} and $PM_{2.5}$ emissions resulting from the Emergency Generators.

Step 4: Evaluate the Most Effective Controls and Document the Results

In its review of the RACT/BACT/LAER Clearinghouse (RBLC) and similar permits, no facilities were identified where controls were required on an emergency generator.

The nature of an emergency generator is to provide electricity to the site only in an emergency situation that arises when the normal operating falls into an emergency status.

The emergency diesel-fired generators are not expected to be used in normal operation. Outside of emergency situations, these engines will only operate for testing and maintenance purposes – which should average no more than one hour per week for each engine (i.e.; 52 hours per year each).

These emergency diesel engines are subject to federal NSPS and NESHAPS standards: Part 60 Subpart IIII and Part 63 Subpart ZZZZ. These standards are applicable to stationary compression ignition internal combustion engines. They establish emissions standards that must be met by the manufacturer and owner/operator regarding NO_x, CO, PM, hydrocarbon (VOC) emissions and fuel sulfur content. The proposed emergency engines of IG will meet these standards.

A search of the RACT/BACT/LAER Clearinghouse indicates good engineering design meeting the above standards and burning low sulfur diesel fuel (15 ppm sulfur) have been considered BACT for emergency diesel engines / generators for all pollutants. The use of further add-on controls would not be justified given the infrequent use of this equipment. IG proposes to limit each engine to no more than 52 hours per year of non-emergency operation (consistent with the basis of the annual emissions air dispersion modeling.)

Therefore, the IG Facility proposes that BACT for these emergency engines is compliance with NSPS Subpart IIII, NESHAPS Subpart ZZZZ and the burning of fuels with no more than 15 ppm sulfur for all BACT pollutants. IG will also limit the non-emergency operation of these engines to no more than 52 hours per year each.

(a) **Proposal**: **Indiana Gasification, LLC - Rockport, IN**

The following has been proposed as BACT for the NOx, CO, SO2 PM, PM_{10} and $PM_{2.5}$ emissions from the emergency generators:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM, OAQ has approved the proposed NOx, CO, SO2 PM, PM_{10} and $PM_{2.5}$ BACT for the Emergency Generators.

The BACT for Emergency Generators shall be established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur l) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation.

Nitrogen Oxide (NO_X), CO, SO_2, $PM/PM_{10}/PM_{2.5}$ BACT - Firewater Pump Engines (EU-010A-C)

Step 1: Identify Potential Control Technologies

These engines are used in emergencies only and operate about 50 hours a year to ensure that they will start when needed. They will be designed to meet the applicable NSPS and NESHAP limited discussed below. Combustion design will be used by the manufacturer to meet those limits. These units will be operated on low sulfur diesel. Diesel has been chosen over natural gas and SNG for safety reasons. Should an incident affect the gas system, an independent source of fuel, in the form of a localized dedicated fuel tank, is available. Beyond the use of low sulfur diesel, which has beneficial impacts on both the SO_2 and particulate emissions of the unit, the emissions of Nitrogen oxide (NOx), CO, SO_2, PM, PM_{10} and $PM_{2.5}$ from firewater pump engines are not generally controlled.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing NOx, CO, SO_2, PM, PM_{10} and $PM_{2.5}$ emissions from the Firewater Pump Engines. No additional controls have been identified.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the NOx, CO, SO_2 PM, PM_{10} and $PM_{2.5}$ emissions resulting from the Firewater Pump Engines.

Step 4: Evaluate the Most Effective Controls and Document the Results

In its review of the RACT/BACT/LAER Clearinghouse (RBLC) and similar permits, no facilities were identified where controls were required on the Firewater Pump Engines.
The firewater pumps are not expected to be used in normal operation. Outside of emergency situations, these engines will only operate for testing and maintenance purposes – which should average no more than one hour per week for each engine (i.e.; 52 hours per year each).

These firewater pumps are subject to federal NSPS and NESHAPS standards: Part 60 Subpart IIII and Part 63 Subpart ZZZZ. These standards are applicable to stationary compression ignition internal combustion engines. They establish emissions standards that must be met by the manufacturer and owner/operator regarding NOx, CO, PM, hydrocarbon (VOC) emissions and fuel sulfur content. The proposed emergency engines will meet these standards.

A search of the RACT/BACT/LAER Clearinghouse indicates good engineering design meeting the above standards and burning low sulfur diesel fuel (15 ppm sulfur) have been considered BACT for emergency diesel engines/generators for all pollutants. The use of further add-on controls would not be justified given the infrequent use of this equipment. IG proposes to limit each engine to no more than 52 hours per year of non-emergency operation (consistent with the basis of the annual emissions air dispersion modeling.)

Therefore, BACT for these emergency engines is compliance with NSPS Subpart IIII, NESHAPS Subpart ZZZZ and the burning of fuels with no more than 15 ppm sulfur for all BACT pollutants. The non-emergency operation of these engines will be limited to no more than 52 hours per year each.

(a) **Proposal: Indiana Gasification, LLC - Rockport, IN**

The following has been proposed as BACT for the NOx, CO, SO_2 PM, PM_{10} and $PM_{2.5}$ emissions from the firewater pump engines:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfurl) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM, OAQ has approved the proposed NOx, CO, SO_2 PM, PM_{10} and $PM_{2.5}$ BACT for the Firewater Pump Engines.

The BACT for firewater pump engines shall be established as follows:

(1) NOx: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(2) CO: emissions shall be limited through the implementation of good combustion practices and limited hours of non-emergency operation;

(3) PM, PM_{10} and $PM_{2.5}$: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation;

(4) SO_2: emissions shall be limited through the use of low-S diesel (less than15ppm sulfur) and limited hours of non-emergency operation; and

(5) Each emergency generator shall not exceed 52 hours per year of non-emergency operation.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Process Area Solid Feedstock Conveying, storage and feedbin (EU-011 A and B)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and $PM_{2.5}$ are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

(a) **Fabric Filtration (Baghouses):**

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The Process Area Coal/Coke Feed to Gasifier material handling step includes coal and coke handling systems inside the process block that deliver coal and/or coke to the gasifiers. There are two systems (one plus a spare). This system is smaller than the large conveyance system from the docks to the coal pile and is proposed to be controlled by a baghouse. The dry dust collected by the baghouse will be fed directly to the rodmills. Whereas the wastewater from a wet scrubbing system would have to be treated to increase the solids concentration before it could be fed to the rod mills in order to maintain the required high solids concentration in the slurry from the rod mill.

The ability to directly feed the collected dust to the rodmills minimizes the handling and storage of fine combustible dust and decreases the fire and explosion risk of a dry collection system. In some other instances, a dry collection system would be judged to be too high a safety risk for combustible dust control. However, in this service, with an available process outlet (the wet rodmill), the fire and explosion risk is significantly decreased.

All of the material handling steps are ducted to the top of the feedstock silos (day bins) and have a single emissions point from the top/outlet of the silos. Only one dust collection system is in use at a time.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a fabric filter is a technically feasible option for the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) at this source.

(b) **Wet Scrubber**

A wet scrubber is an air pollution control device that removes particulates from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulates. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream.

In general, collection efficiency decreases as the particulates size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 90% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulates with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles that are difficult to remove in their dry form;

(4) Particulates in the presence of soluble gases; and

(5) Particulates in waste gas streams with high moisture content.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is a technically feasible option for the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) at this source.

(c) **Cyclones:**

Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs. Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is a technically feasible option for the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) at this source.

(d) **Wet Suppression:**
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression is a technically feasible option for the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of a coal and coke handling system.

(1) Fabric Filtration (≥ 99% PM/PM10/PM2.5 Reduction);

(2) Wet Scrubber (> 90% PM/PM10/PM2.5 Reduction);

(3) Wet Suppression (90% PM/PM10/PM2.5 Reduction); and

(4) Cyclones (80% PM/PM10/PM2.5 Reduction).

As shown above, baghouse achieves a control efficiency of greater than 99% versus the wet scrubber, wet suppression and cyclone control efficiency of 90%, 85% and 80%, respectively. Thus, the use of a baghouse is the top ranked control alternative for control of particulate matter emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Process Area Solid Feedstock Conveying, storage and feedbin**	**10,400 T dry coal/day**	**PM/PM_{10}/: 0.003 gr/dscf $PM_{2.5}$: 0.0015 gr/dscf**	**Baghouse**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control

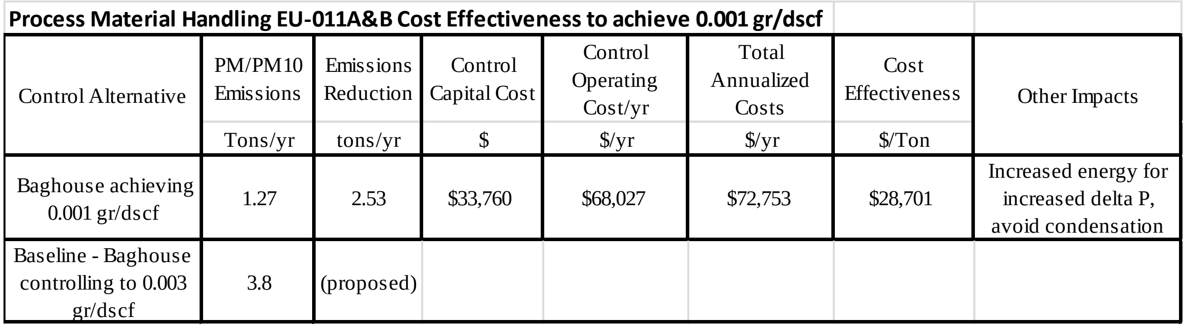
BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating cost for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.



Process Material Handling EU-011A&B Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	1.27	2.53	$33,760	$68,027	$72,753	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	3.8	(proposed)					

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B):

(1) The construction of a baghouse for control of PM, PM_{10} and $PM_{2.5}$ emissions.

(2) The PM and PM_{10} maximum outlet concentration of 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration of 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Process Area Solid Feedstock Conveying, storage and feedbin (EU-011A/B) shall be limited through a baghouse.

(2) The PM and PM_{10} maximum outlet concentration of 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration of 0.0015 gr/dscf.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Incoming Solid Feedstock Material Handling System - Barge Unloading to Hopper Transfer Point (EU-012A)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and $PM_{2.5}$ are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

The barge unloading operation handles bulk quantities of coal and coke unloading. Unloading of barges will be by clamshell crane from the shipping compartment to the hopper of the transfer conveyor. These unloading operations cannot reasonably be enclosed and vented to a control device due to the location outside and due to the extreme size involved. This eliminates the applicability of a collection (Baghouse, Wet Scrubber and Cyclone) and filtration equipment or other “add-on” controls.

The only remaining control for this material handling that is technically feasible is wet or chemical suppression.

Wet Suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression is a technically feasible option for the Barge Unloading (EU-012A) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Wet Suppression (90% PM/PM_{10}/$PM_{2.5}$ Reduction).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling facilities. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	Coal/Coke Barge Unloading	**10,400 T dry coal/day**	**90% control**	**Wet or Chemical Suppression**
IA-0089- Iowa	Homeland Energy Solutions	08/08/2007	Coal Receiving and handling	200 tons/hr	None specified for unenclosed unloading area	water fogging to eliminate particulate in unloading area

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
IA - 0086 - Iowa	University of Northern Iowa	05/3/2007	Coal Pile	50,565 tons/hr	PM/PM10: Must use dust suppressant to reduce fugitive emissions by 95%	Chemical suppressant with 95% control
CO-0057 - Colorado	Public Service Company of Colorado Comanche Station	07/05/2005	Coal handling and storage (includes open storage piles with lowering well, rail-car unloading, transfer from unloading to pile and transfer from pile to bunker)	NA	None specified for unenclosed unloading area	Control include water spray, lower well, dust suppressant, enclosures where baghouse are not feasible
KY-0100	East Kentucky Power Coop.	04/09/2010	Coal Pile, Rail Unloading Egress to Conveyor	3000 tons per hr	10% opacity (3min)	Wet Suppression, Dust suppressant Lowering well and compaction
OH-0317	Ohio River Clean Fuels	11/20/2008	Coal Storage Piles	5500 tons/hr	PM10:12.3 tons per year. with 75% control.	3-sided windscreen barrier. Reduced drop heights. Use of chemical stabilization dust suppressants and/or watering to reduce any visible emissions.

NOTE: * These emission units have not been built yet.
Note: ** Compliance with the limit at this facility has not been demonstrated through stack testing.

The table above shows recent permit conditions for comparable facilities for material handling activities that can’t be enclosed. All these permits specify wet or chemical suppression, consistent with the source's proposal. Although most of the database entries do not specify the level of control, two of the listed entries specify 75% and 95%. Dependent on the amount and frequency of the application of wet suppression, various levels of control can theoretically be achieved by wet suppression. Control of greater than 90% is not normally considered practicable.

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Barge Unloading to hopper transfer point (EU-012A):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the barge unloading to hopper transfer point shall be controlled by the use of wet suppression with a control efficiency of 90%.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for barge unloading (EU-012A).

The PM, PM_{10} and $PM_{2.5}$ emissions from the barge unloading to hopper transfer point (EU-012A) operation shall be controlled by a wet suppression with a control efficiency of 90%.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Rail Unloading to Rail Hoppers (EU-012G/H)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and $PM_{2.5}$ are generally controlled by the following add-on control equipment, designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Electrostatic Precipitator (ESP);

(3) Cyclones; and

(4) Wet Dust Extraction.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

These material handling steps are fully enclosed and proposed to be vented through a dust control system.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Railcar Unloading to Rail Hoppers (EU-012G/H) at this source.

Cyclones or ESPs

Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is theoretically feasible, but they are not as effective as a baghouse or a wet extraction system, which is described next. Since they are no more effective than these control strategies, they are not considered further in this BACT analysis.

Wet Dust Extraction

An alternative effective control system, is a wet extraction system. Such dust extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled to the high efficiency of 99.7% for the IG facility. This alternative technology achieves a similar level of control as baghouses. However wastewater treatment and water freezing in cold weather result in higher maintenance and operating costs versus baghouses.

Wet Dust Extraction System Technical Description

1. Stage 1: Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is ‘wetted’ by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

2. Stage 2: Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers knitmesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by the action of a multi-nozzle spray bank.

3. Stage 3: Demister Vanes: The ‘catchment’ or ‘demister’ vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Dust Extraction is a technically feasible option for the Railcar Unloading to Rail Hoppers (EU-012G/H) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Fabric Filter Dust Collectors (Baghouses) (>99% PM/PM10/PM2.5 Reduction);

(2) Wet Dust Extraction (>99% PM/PM10/PM2.5 Reduction).

The two systems offer comparable control. IG proposes to use one or the other system to meet BACT for this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	Coal/Coke Unloading and Conveyance	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003 gr/dscf** **$PM_{2.5}$: 0.0015 gr/dscf**	**Baghouse or Wet Dust Extraction**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating cost for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Rail Unloading to Rail Hoppers (EU-012G/H):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the railcar unloading to rail hoppers shall be controlled by either wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Railcar Unloading (EU-012G/H).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the railcar unloading to rail hoppers shall be controlled by wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT –Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Electrostatic Precipitator (ESP);

(3) Cyclones; and

(4) Wet Dust Extraction.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

These material handling steps are fully enclosed and proposed to be vented through a dust control system.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.
Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Conveyance from Barge Hopper to pile Stacker (EU-012B-F) at this source.

Cyclones or ESPs

Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is theoretically feasible, but they are not as effective as a baghouse or wet extraction system, which is described next. Since they are no more effective than the proposed control strategy, they are not considered further in this BACT analysis.

Wet Dust Extraction

Wet dust extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled to the high efficiency of 99.7% for the IG facility. This alternative technology achieves a similar level of control as baghouses. However wastewater treatment and water freezing in cold weather result in higher maintenance and operating costs versus baghouses.

Wet Dust Extraction System Technical Description

1. Stage 1: Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is ‘wetted’ by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

2. Stage 2: Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers knitmesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by the action of a multi-nozzle spray bank.

3. Stage 3: Demister Vanes: The ‘catchment’ or ‘demister’ vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Dust Extraction is a technically feasible option for the Conveyance from Barge Hopper to pile Stacker (EU-012B-F) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Baghouse fabric filter (>99% PM/PM_{10}/$PM_{2.5}$ Reduction)

(2) Wet Dust Extraction (≥ 99% PM/PM_{10}/$PM_{2.5}$ Reduction).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Conveyance**	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003 gr/dscf $PM_{2.5}$: 0.0015 gr/dscf**	**Baghouse or Wet Dust Extraction**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Conveyance from barge Hopper to Pile Stacker (EU-012B-F).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Barge Unloading from the Hopper to the Belt (EU-012B) and Barge Conveyor Transfer Points (EU-012C-F) shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT –Rail Hoppers Unloading to the Conveyor Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Electrostatic Precipitator (ESP);

(3) Cyclones; and

(4) Wet Dust Extraction.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

These material handling steps are fully enclosed and proposed to be vented through a dust control system.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.
Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Conveyance from Rail Hopper to pile Stacker (EU-012I-K) at this source.

Cyclones or ESPs

Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is theoretically feasible, but they are not as effective as proposed baghouse or a wet extraction system, which is described next. Since they are no more effective than the proposed control strategy, they are not considered further in this BACT analysis.

Wet Dust Extraction

Wet dust extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled to the high efficiency of 99.7% for the IG facility. This alternative technology achieves a similar level of control as baghouses. However wastewater treatment and water freezing in cold weather result in higher maintenance and operating costs versus baghouses.

Wet Dust Extraction System Technical Description

1. Stage 1: Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is ‘wetted’ by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

2. Stage 2: Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers knitmesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by the action of a multi-nozzle spray bank.

3. Stage 3: Demister Vanes: The ‘catchment’ or ‘demister’ vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Dust Extraction is a technically feasible option for the Conveyance from Rail Hopper to pile Stacker (EU-012I-K) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Baghouse fabric filter (>99% PM/PM_{10}/$PM_{2.5}$ Reduction)

(2) Wet Dust Extraction (≥ 99% PM/PM_{10}/$PM_{2.5}$ Reduction).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Conveyance**	**10,400 T dry coal/day**	**PM/PM10: 0.003 gr/dscf PM2.5: 0.0015 gr/dscf**	**Baghouse or Wet Dust Extraction**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG’s engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM$_{10}$ and PM$_{2.5}$ from the proposed Rail Hopper Unloading to the Conveyor Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K):

(1) The PM, PM$_{10}$ and PM$_{2.5}$ emissions shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM$_{10}$ maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The PM$_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM$_{10}$ and PM$_{2.5}$ for the Rail Hopper Unloading to the Conveyor Belts (EU-012I-J) and Rail Conveyor Belt to the Stacker (EU-012K):

(1) The PM, PM$_{10}$ and PM$_{2.5}$ emissions shall be controlled by a wet dust extraction or baghouse.

(2) The PM and PM$_{10}$ maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The PM$_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter (PM/PM$_{10}$/PM$_{2.5}$) BACT – Stacker Belts to the Radial Stacker (EU-012 L- M)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM$_{10}$ and PM$_{2.5}$ are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Electrostatic Precipitator (ESP);

(3) Cyclones; and

(4) Wet Dust Extraction.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

These material handling steps are fully enclosed and proposed to be vented through a dust control system.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.
Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Conveyance from Stacker Belt to Stacker (EU-012 L-M) at this source.

Cyclones or ESPs
Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is theoretically feasible, but they are not as effective as the proposed baghouse or wet extraction system, which is described next. Since they are no more effective than the proposed control strategy, they are not considered further in this BACT analysis.

Wet Dust Extraction

Wet dust extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled to the high efficiency of 99.7% for the IG facility. This alternative technology achieves a similar level of control as baghouses. However wastewater treatment and water freezing in cold weather result in higher maintenance and operating costs versus baghouses.

Wet Dust Extraction System Technical Description

1. Stage 1: Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is ‘wetted’ by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

2. Stage 2: Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers knitmesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by the action of a multi-nozzle spray bank.

3. Stage 3: Demister Vanes: The ‘catchment’ or ‘demister’ vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Dust Extraction is a technically feasible option for the Conveyance from Stacker Belt to Stacker (EU-012 L-M) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Baghouse fabric filter (>99% PM/PM_{10}/$PM_{2.5}$ Reduction)

(2) Wet Dust Extraction (≥ 99% PM/PM_{10}/$PM_{2.5}$ Reduction).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Conveyance**	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003 gr/dscf $PM_{2.5}$: 0.0015 gr/dscf**	**Baghouse or Wet Dust Extraction**
081801 AAF (Application No.	Power Holdings of Illinois	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control

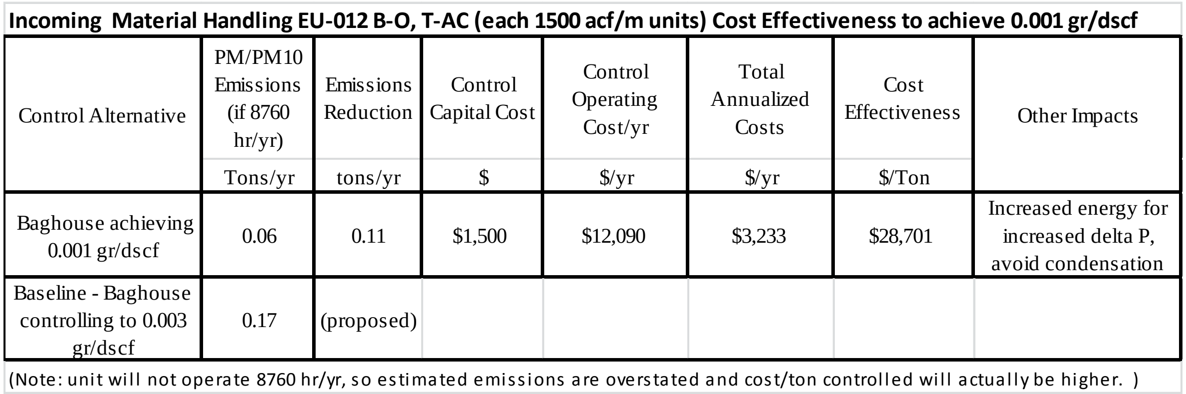
BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
07100063)	Gasification					
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration , LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.



Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a)

Proposal: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Stacker Belts to the Radial Stacker (EU-012 L-M):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belts to the Radial Stacker shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Stacker Belt to Stacker (EU-012L-M).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Stacker Belts to the Radial Stacker shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU – 012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Electrostatic Precipitator (ESP);

(3) Cyclones; and

(4) Wet Dust Extraction.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

These material handling steps are fully enclosed and proposed to be vented through a dust control system.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU – 012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V) at this source.

Cyclones or ESPs
Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is theoretically feasible, but they are not as effective as a baghouse or a wet extraction system, which is described next. Since they are no more effective than the proposed control strategy, they are not considered further in this BACT analysis.

Wet Dust Extraction
Wet dust extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled to the high efficiency of 99.7% for the IG facility. This alternative technology achieves a similar level of control as baghouses. However wastewater

treatment and water freezing in cold weather result in higher maintenance and operating costs versus baghouses.

Wet Dust Extraction System Technical Description:

1. Stage 1: Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is 'wetted' by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

2. Stage 2: Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers knitmesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by the action of a multi-nozzle spray bank.

3. Stage 3: Demister Vanes: The 'catchment' or 'demister' vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Dust Extraction is a technically feasible option for the Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU – 012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Baghouse fabric filter (>99% PM/PM_{10}/$PM_{2.5}$ Reduction)

(2) Wet Dust Extraction (≥ 99% PM/PM_{10}/$PM_{2.5}$ Reduction).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Conveyance**	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003 gr/dscf** **$PM_{2.5}$: 0.0015 gr/dscf**	**Baaghouse or Wet Dust Extraction**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical	630 MW	0.003 gr/dscf	Baghouse

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
			facilities)*			
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.

Incoming Material Handling EU-012 R&S (each 6000 acfm units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.23	0.45	$6,000	$12,090	$12,930	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.68	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU – 012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Transfer systems consisting of hoppers and conveyor belts transferring feed stock from the piles to classification towers (EU – 012R-S); Classification towers (EU-012T-U); and Classification tower to a day bin (EU-012V).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a wet dust extraction or a baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Radial Stackers to the Pile (EU-012 N-O)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Cyclones;

(3) Wet Suppression; and

(4) Telescoping Chutes.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

(a) **Fabric Filtration (Baghouses):**
A fabric filtration system is not feasible for an operation that cannot reasonably be enclosed with the emissions routed to a control device. The nature of pile loading does not naturally lend itself to enclosure. However, through the use of telescoping loading chutes (discussed below) the loading emissions can be routed to an add-on control device. Therefore, although a fabric filter would not normally be feasible, in combination with a suitable enclosure, it is a feasible control for this operation.

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The use of a filter that is incorporated into the loading chute allows the collected dust to be deposited with the material being loaded. This avoids the separate accumulation of combustible dust, lengthy ductwork, or separate systems to transport combustible dusts back to the process. These features make a dry filter use in this application less hazardous than in the other material transfer operations at this plant.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a fabric filter alone is not technically feasible option for the Process Coal/Petcoke Radial Stacker to Pile (EU-012N-O) at this source but it could be used as part of a system that includes enclosure of the emissions.

(b) **Cyclones:**

Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs. Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is a technically feasible option for the Process Radial Stackers to the Pile (EU-012N-O) at this source if used as part of a system that includes enclosure of the emissions

(c) **Wet Suppression:**
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression is a technically feasible option for the Process Radial Stackers to the Pile (EU-012N-O) at this source.

(d) **Telescoping Chutes**
In this process, the incoming feedstocks are dropped from the end of the transfer conveyor onto the storage pile. Typical controls for loading materials onto a pile include the use of wet suppression and or the use of telescoping chutes that reduce the distance of, and enclose, the drop. These controls can provide greater than 85% control.

To achieve significantly higher levels of control, firms such as DCL, Inc. provide telescoping chutes for bulk material pile loading coupled with a dust collector system. This type of system allows coal/petcoke to flow down through a central telescoping flow tube onto the pile while dust is captured and drawn upward through an outer telescoping tube with a fan vented to a dust collector filter system. This system guarantees 99.9% dust collector control efficiency with an outlet loading comparable to other baghouses 0.005 gr/dscf particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a telescoping chute is a technically feasible option for the Process Radial Stackers to the Pile (EU-012N-O) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of the Process Radial Stackers to the Pile (EU-012N-O) at this source.

(1) Telescoping Chute with dust collection filtration system (≥99% PM/PM10/PM2.5 Reduction);

(2) Wet Suppression (90% PM/PM10/PM2.5 Reduction); and

(3) Cyclones (80% PM/PM10/PM2.5 Reduction).

As shown above, baghouse and the telescoping chute with dust collection filtration system achieves a control efficiency of greater than 99% versus the wet suppression and cyclone control efficiency of 90% and 80%, respectively. Therefore, the source has decided to use the telescoping chute with dust collection filtration system which is one of the top ranked control alternatives for control of particulate matter emissions from the Radial Stackers to the Pile (EU-012N-O).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

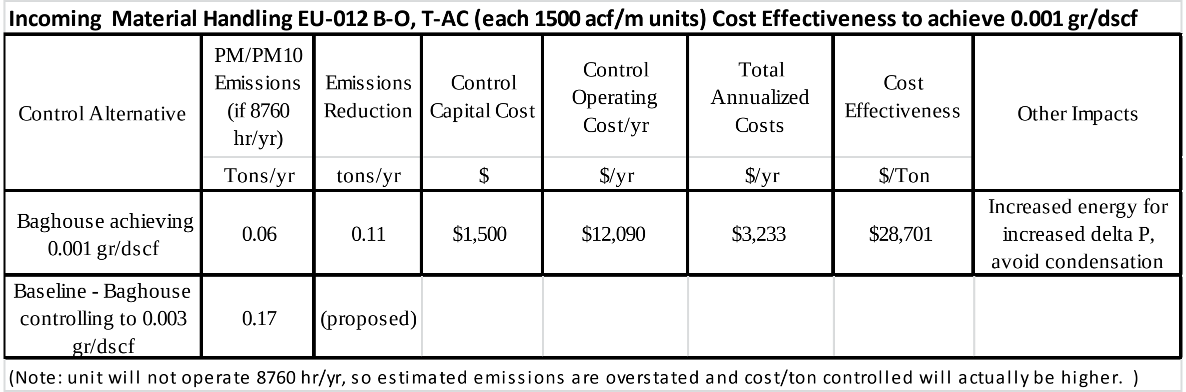
BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Barge Unloading and Storage**	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003 gr/dscf $PM_{2.5}$: 0.0015 gr/dscf**	**Telescoping Chute with dust collection or Baghouse**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit.



Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Radial Stackers to the Pile (EU-012 N-O):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a Telescoping chute with dust collection.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf, each.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Radial Stackers to the Pile (EU-012N-O).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by a Telescoping chute with dust collection.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf, each.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015 gr/dscf.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Storage Piles (EU-012W/X)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are often controlled by the following controls designed to prevent or capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

The coal pile wind erosion and dozer operations cannot reasonably be enclosed and vented to a control device due to the location outside and due to the extreme size involved. This eliminates the applicability of collection and filtration equipment or other add-on controls.

The only remaining controls for this material handling that is technically feasible for these sources is wet or chemical suppression and the use of pile compaction. Frequent use of water or chemical surfactants can significantly reduce airborne dust from transfer operations.

Wet Suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles.

There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%

The source will use pile compaction and apply wet or chemical suppression to achieve reduction of 90% particulate matter (PM_{10}). (Note: The use of either plain water or water with chemical surfactants added can provide equally effective control, given adequate application rate and frequency. The use of chemical additives primarily allows a decrease in frequency of application, but it increases the cost of each application.)

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression and Pile compaction are technically feasible option for the Storage Piles (EU-012W/X) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Wet Suppression and Pile Compaction (90% PM/PM10/PM2.5 Reduction).

These operations cannot reasonably be enclosed and vented to a control device due to the location outside and due to the extreme size involved. This eliminates the applicability of collection and filtration equipment. The only remaining controls for this material handling that is technically feasible for these sources is wet or chemical suppression and the use of pile compaction. Frequent use of water or chemical surfactants can significantly reduce airborne dust from transfer operations. IG will use pile compaction and apply wet or chemical suppression to achieve reduction of 90% particulate matter (PM_{10}).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling facilities. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	Coal/Coke Pile	**10,400 T dry coal/day**	**90% control**	**Wet Suppression with Pile Compaction**
IA-0089- Iowa	Homeland Energy Solutions	08/08/2007	Coal Receiving and handling	200 tons/hr	None specified for unenclosed unloading area	water fogging to eliminate particulate in unloading area
IA - 0086 - Iowa	University of Northern Iowa	05/3/2007	Coal Pile	50,565 tons/hr	PM/PM10: Must use dust suppressant to reduce fugitive emissions by 95%	Chemical suppressant with 95% control
CO-0057 - Colorado	Public Service Company of Colorado Comanche Station	07/05/2005	Coal handling and storage (includes open storage piles with lowering well, rail-car unloading, transfer from unloading to pile and transfer from pile to bunker)	NA	None specified for unenclosed unloading area	Control include water spray, lower well, dust suppressant, enclosures where baghouse are not feasible
KY-0100	East Kentucky Power Coop.	04/09/2010	Coal Pile, Rail Unloading Egress to Conveyor	3000 tons per hr	10% opacity (3min)	Wet Suppression, Dust suppressant Lowering well and compaction
OH-0317	Ohio River Clean Fuels	11/20/2008	Coal Storage Piles	5500 tons/hr	PM10:12.3 tons per year. with 75% control.	3-sided windscreen barrier. Reduced drop heights. Use of chemical stabilization dust suppressants and/or watering to reduce any visible emissions.

NOTE: * These emission units have not been built yet.
Note: ** Compliance with the limit at this facility has not been demonstrated through stack testing.

The table above shows recent entries in the RACT/BACT/LAER Clearinghouse (RBLC) database for material handling activities that can't be enclosed. All these permits specify wet or chemical suppression, consistent with the source's proposal. Although most of the database entries do not specify the level of control, two of the listed entries specify 75% and 95%. Dependent on the amount and frequency of the application of wet suppression, various levels of control can theoretically be achieved by wet suppression. Control of greater than 90% is not normally considered practicable.

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Storage Piles (EU-012W/X):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Storage Piles (EU-012W/X).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Storage Piles (EU-012W/X) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Dozer Activities (EU-012P/Q)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and $PM_{2.5}$ are generally controlled by the following controls designed to prevent or capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Fabric Filter Dust Collectors (Baghouses);

(2) Wet Scrubber;

(3) Cyclones; and

(4) Wet Suppression.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

The coal pile wind erosion and dozer operations cannot reasonably be enclosed and vented to a control device due to the location outside and due to the extreme size involved. This eliminates the applicability of collection and filtration equipment or other add-on controls.

The only remaining controls for this material handling that is technically feasible for these sources is wet or chemical suppression and the use of pile compaction. Frequent use of water or chemical surfactants can significantly reduce airborne dust from transfer operations.

Wet Suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles.

There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%

The source will use pile compaction and apply wet or chemical suppression to achieve reduction of 90% particulate matter (PM_{10}). (Note: The use of either plain water or water with chemical surfactants added can provide equally effective control, given adequate application rate and frequency. The use of chemical additives primarily allows a decrease in frequency of application, but it increases the cost of each application.)

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet suppression and Pile compaction is a technically feasible option for the Dozer Activity (EU-012P/Q) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Wet Suppression and Pile Compaction (90% $PM/PM_{10}/PM_{2.5}$ Reduction).

These operations cannot reasonably be enclosed and vented to a control device due to the location outside and due to the extreme size involved. This eliminates the applicability of collection and filtration equipment. The only remaining controls for this material handling that is technically feasible for these sources is wet or chemical suppression and the use of pile compaction. Frequent use of water or chemical surfactants can significantly reduce airborne dust from transfer operations. IG will use pile compaction and apply wet or chemical suppression to achieve reduction of 90% particulate matter (PM_{10}).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling facilities. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	Coal/Coke Pile	**10,400 T coal/day**	**90% control**	**Wet Suppression with Pile Compaction**
IA-0089- Iowa	Homeland Energy Solutions	08/08/2007	Coal Receiving and handling	200 tons/hr	None specified for unenclosed unloading area	water fogging to eliminate particulate in unloading area

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
IA - 0086 - Iowa	University of Northern Iowa	05/3/2007	Coal Pile	50,565 tons/hr	PM/PM10: Must use dust suppressant to reduce fugitive emissions by 95%	Chemical suppressant with 95% control
CO-0057 - Colorado	Public Service Company of Colorado Comanche Station	07/05/2005	Coal handling and storage (includes open storage piles with lowering well, rail-car unloading, transfer from unloading to pile and transfer from pile to bunker)	NA	None specified for unenclosed unloading area	Control include water spray, lower well, dust suppressant, enclosures where baghouse are not feasible
KY-0100	East Kentucky Power Coop.	04/09/2010	Coal Pile, Rail Unloading Egress to Conveyor	3000 tons per hr	10% opacity (3min)	Wet Suppression, Dust suppressant Lowering well and compaction
OH-0317	Ohio River Clean Fuels	11/20/2008	Coal Storage Piles	5500 tons/hr	PM10:12.3 tons per year. with 75% control.	3-sided windscreen barrier. Reduced drop heights. Use of chemical stabilization dust suppressants and/or watering to reduce any visible emissions.

NOTE: * These emission units have not been built yet.
Note: ** Compliance with the limit at this facility has not been demonstrated through stack testing.

The table above shows recent entries in the RACT/BACT/LAER Clearinghouse (RBLC) database for material handling activities that can’t be enclosed. All these permits specify wet or chemical suppression, consistent with the source's proposal. Although most of the database entries do not specify the level of control, two of the listed entries specify 75% and 95%. Dependent on the amount and frequency of the application of wet suppression, various levels of control can theoretically be achieved by wet suppression. Control of greater than 90% is not normally considered practicable.

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Dozer Activities (EU-012P/Q):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Dozer Activities (EU-012P/Q) shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Dozer Activities (EU-012P/Q).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Dozer Activities (EU-012P/Q) operation shall be controlled by wet suppression with pile compaction with a control efficiency of 90 %.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor belts (EU-012AA)

Step 1: Identify Potential Control Technologies

The emissions of PM, PM_{10} and PM2.5 are generally controlled by the following add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere:

(1) Filtration
  (a) Baghouse,
  (b) Wet Extraction System (fan/water sprays/extraction/demister), and

(2) Other Add-on Controls (Cyclone, ESP)

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Cyclone/Electrostatic Precipitator

Use of add-on controls such as cyclones or electrostatic precipitators (ESP) is not good technical choices in this service because of the relatively low flow rates. Additionally, for this service, they are not as effective as the proposed baghouse or wet extraction system and are therefore not considered further in this BACT analysis.

Fabric Filter (Baghouse)
A baghouse fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%.

The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 1 to 20 inches of water.
Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties.

The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is a technically feasible option for the Truck unloading (EU-012Y-AC) at this source.

Wet Extraction System

Wet extraction systems are designed specifically for high-efficiency dust control. The design accomplishes this by spraying water into the air stream at the suction of a high volume fan. Using a combination of the energy of the fan and the water, the dust particles are trapped into finely atomized water droplets which are removed from the fan exhaust in an extractor panel and demister. Dust is expected to be controlled for the IG facility at an efficiency rate of 99% (at maximum design loading). The below figure shows the major components of this control system and is followed by a further technical explanation of how each stage of the system works.

Wet extraction System Technical Description

Stage 1 Water Injection: Dust laden air is drawn into the dust extractor fan where it is mixed with water that is discharged from the water spray nozzles. The dust-laden air is ‘wetted’ by a mechanical action as it passes through the impeller, which is rotating at approx. 3600 rpm. The dust/water and air mixture then passes around the motor to an extractor panel.

Stage 2 Extractor Panel: The dust/water and air mixture passes through a woven mesh extractor panel. The mesh contains multiple layers of knit mesh. The dust particle laden water is separated from the airstream within the panel and drains away. Additionally, the panel is periodically washed as needed by a multi-nozzle spray bank.

Stage 3 Demister Vanes: The ‘catchment’ or ‘demister’ vanes collect excess water and dust mixture that has not drained away in the extractor panel, so that there is little water carried through the unit ensuring only dry, clean air is exhausted.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet extraction system is a technically feasible option for the Truck unloading (EU-012 Y-AC) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Baghouse (> 99% PM/PM10/PM2.5 Reduction)

(2) Wet Dust Extraction System (≥ 99% $PM/PM_{10}/PM_{2.5}$ Reduction).

These systems provide comparable control effectiveness.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for coal handling operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Coal/Coke Truck Unloading and Conveyance**	**10,400 T dry coal/day**	**PM/PM_{10}: 0.003gr/dscf $PM_{2.5}$: 0.0015 gr/dscf**	**Baghouse or Wet Dust Extraction System**
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Coal-Coke Handling System (2 identical facilities) *	13,722 T coal per day	0.001 gr/dscf	Baghouse or similar control
T083-23529-00003	Duke Energy Indiana - Edwardsport	01/25/2008	Coal-Coke Handling System (2 identical facilities)*	630 MW	0.003 gr/dscf	Baghouse
PSD-LA-742(M1) Louisiana	Lake Charles Cogeneration, LLC	12/30/2010	Coal-Coke Handling System (2 identical facilities)*	9,413 T/D	0.005 gr/dscf	Baghouse
28.0701-PSD	Hyperion Energy	08/20/2009	Coal-Coke Handling System (2 identical facilities)*	400,000 bbl/day	0.005 gr/dscf	Baghouse
Permit V-09-006	Cash Creek Gasification	05/05/2010	Coal-Coke Handling System (2 identical facilities)*	770 MW	0.005 gr/dscf	Baghouse

NOTE: * These emission units have not been built yet.

The majority of the above baghouse systems are permitted with a performance specification of 0.005 gr/dscf. This is consistent with almost all entries found in the RBLC database for baghouses and is standard design for an efficient baghouse. In special circumstances, baghouses can be designed to achieve even lower outlet PM, PM_{10} and $PM_{2.5}$ emissions. Evidently, as shown in the above table, the Power Holdings and Duke Edwardsport gasification plants intend to have such systems for at least some of their material handling operations. However, this higher control efficiency comes at a significant additional cost.

According to IG's engineering design firm, achieving 0.001 gr/dscf is very difficult and expensive for a bulk material handling baghouse. It is generally achievable with PTFE (Teflon) bags, very low air-to-cloth ratio (i.e.: requiring a large unit), a low pressure/high volume bag cleaning-type unit, bag cleaning on demand, and other such special features. It also critical that the air going through the dust collector always be above the dew point (PTFE bags will pass moisture vapor but condensed water droplets will blind the bags), so it can require heated structures, insulated ductwork, and heated and insulated dust collectors. All these elements come at additional expense.

For this specific emissions source, the incremental costs to achieve 0.001 gr/dscf are unreasonably high for the small benefit obtained. This is illustrated in the below cost analysis which considers the estimated incremental capital and operating costs for each baghouse to achieve this extremely low emissions and shows that the cost-effectiveness is greater than $10,000/ton of PM controlled for this emission unit

Incoming Material Handling EU-012 B-O, T-AC (each 1500 acf/m units) Cost Effectiveness to achieve 0.001 gr/dscf

Control Alternative	PM/PM10 Emissions (if 8760 hr/yr)	Emissions Reduction	Control Capital Cost	Control Operating Cost/yr	Total Annualized Costs	Cost Effectiveness	Other Impacts
	Tons/yr	tons/yr	$	$/yr	$/yr	$/Ton	
Baghouse achieving 0.001 gr/dscf	0.06	0.11	$1,500	$12,090	$3,233	$28,701	Increased energy for increased delta P, avoid condensation
Baseline - Baghouse controlling to 0.003 gr/dscf	0.17	(proposed)					

(Note: unit will not operate 8760 hr/yr, so estimated emissions are overstated and cost/ton controlled will actually be higher.)

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor belts (EU-012AA):

(1) An enclosed vent to a wet dust extraction system or a baghouse for control of PM, PM_{10} and $PM_{2.5}$ emissions.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015gr/dscf.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor belts (EU-012AA).

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Truck/rail conveyor transfer tower (EU-012Y); truck stations unloading to a truck hopper (EU-012AB-AC); and truck hopper unloading to the conveyor belts (EU-012AA) shall be controlled by an enclosed vent to a wet dust extraction system or baghouse.

(2) The PM and PM_{10} maximum outlet concentration shall not exceed 0.003 gr/dscf.

(3) The $PM_{2.5}$ maximum outlet concentration shall not exceed 0.0015gr/dscf.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT– Rod Mill Vent (EU-013A-D)

Step 1: Identify Potential Control Technologies

Emissions PM, PM_{10} and PM2.5 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, PM and PM_{10} 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.

Step 2: Eliminate Technically Infeasible Options

(a) **Add-on Control Technology:** The rod-mill eductor has a small amount of particulate (PM_{10} emissions are estimated to be 0.44 tons per year total for four rod mills). This low emissions rate is due to the fact that the rod-mill is a wet grinding operation. The high moisture content effectively minimizes the particulate emissions and results in an exhaust particulate concentration of about 0.015 grains/dscf PM/PM_{10}, which is equivalent to 0.025 pounds per hour at permitted capacity, and 0.0047 grains/dscf $PM_{2.5}$, which is equivalent to 0.0074 pounds per hour at permitted capacity.This emissions level is so low that it would not be feasible for any add-on controls such as cyclones, baghouses, ESPs or wet scrubbers to effectively further reduce emissions. These control devices are generally not used on streams with less than 1 grain/scf. Also, regardless of the emissions rate, the high moisture content of this exhaust would create technical difficulties using the more effective of these add-on control devices, the ESP and the baghouses. For these reasons, the above listed add-on particulate controls are not considered feasible in the BACT analysis.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the $PM/PM_{10}/PM_{2.5}$ emissions resulting from the Rod Mill Vent (EU-013A-D).

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for $PM/PM_{10}/PM_{2.5}$ from each proposed Rod Mill Vent at the Indiana Gasification Plant.

For each Rod Mill Vent, BACT for PM/PM_{10} is proposed to be 0.025 pounds per hour based on a 3-hour average and for $PM_{2.5}$ is proposed to be 0.0074 pounds per hour based on a 3-hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for $PM/PM_{10}/PM_{2.5}$ for the Rod Mill Vents.

(a) The PM and PM_{10} emissions from each Rod Mill Vents shall not exceed 0.025 pounds per hour based on a 3-hour average.

(b) The $PM_{2.5}$ emissions from each Rod Mill Vent shall not exceed 0.0074 pounds per hour based on a 3-hour average.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – ASU Regeneration Vent (EU-017A and B)

Step 1: Identify Potential Control Technologies

Emissions of PM, PM_{10} and $PM_{2.5}$ 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, PM/PM_{10}/ $PM_{2.5}$ 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.

Step 2: Eliminate Technically Infeasible Options

(a) **Add-on Control Technology:** The air separation unit molecular sieve regeneration vent is a very small particulate source (PM_{10} emissions are estimated to be 0.22 tons/yr.) that operates intermittently throughout the day. These low emissions are merely dust filtered out of the ambient air used in the air separation unit and represent less than 0.00005 grain/dscf PM/$PM_{10/}$/ $PM_{2.5}$ concentration in the exhaust. This emissions level is so low that it would not be feasible for any add-on controls such as cyclones, baghouses, ESPs or wet scrubbers to effectively further reduce emissions. These control devices are generally not used on streams with less than 1 grain/scf. For this reason, the above listed add-on particulate controls were not considered feasible in the BACT analysis.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the PM/PM_{10}/$PM_{2.5}$ emissions resulting from the Air Separation Unit (ASU) (EU-017A/B).

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for PM/PM_{10}/$PM_{2.5}$ from the proposed Air Separation Unit (ASU) at the Indiana Gasification Plant.

For each ASU, BACT for PM/PM_{10} is proposed to be 0.026 pounds per hour based on a daily average and for $PM_{2.5}$ is proposed to be 0.009 pounds per hour based on a daily average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM/PM_{10}/$PM_{2.5}$ for the Air Separation Unit (ASU).

(a) The PM and PM_{10} emissions from each Air Separation Unit (ASU) shall not exceed 0.026 pounds per hour based on a daily average.

(b) The $PM_{2.5}$ emissions from the Air Separation Unit (ASU) shall not exceed 0.0009 pounds per hour based on a daily average.

PM, PM10 and PM2.5 BACT – Wet Sulfuric Acid Plants (EU-015 A and B)

Step 1: Identify Potential Control Technologies

Emissions of PM, PM10 and PM2.5 are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Cyclones;

(2) Wet Scrubber;

(3) Electrostatic Precipitators (ESP);

(4) Fabric Filter Dust Collectors (Baghouses); and

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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:
One or more alternate methods of control may be considered when they are more cost-effective than the conventional add-on controls or when add-on control technology may not be feasible. For the particulate emission sources from the WSA, the following alternate control methods were evaluated:

(1) Mist eliminators and Hydrogen peroxide (H_2O_2) scrubber

Step 2: Eliminate Technically Infeasible Options

(a) **Add-on Control Technology:** Add on control devices such as fabric filters and electrostatic precipitators (ESPs) are not technically feasible for this source, because the particulates are wet condensable, corrosive acid mist. Based on availability and applicability, the conventional add-on control technology was eliminated from consideration due to technical infeasibility.

(b) **Mist eliminators and Hydrogen peroxide (H_2O_2) scrubber**
The final step in the WSA process involves absorbing and recovering the produced sulfuric acid. A small amount of sulfuric acid mist can carry out with the tail gas. This sulfuric acid mist (H_2SO_4) is also considered $PM/PM_{10}/PM_{2.5}$ for BACT review purposes. To control these emissions, a high efficiency mist elimination filter is installed downstream of the hydrogen peroxide scrubber that captures 75 percent of the fine acid mist. This removal percentage is guaranteed by the equipment vendor. This is the most efficient mist filter available. While the peroxide scrubber that is located upstream of the mist eliminator is installed primarily to control SO_2, it is also estimated to remove 10% of the acid mist prior to the high efficiency mist eliminator filter. The peroxide scrubber uses

a 50% hydrogen peroxide (H_2O_2) solution which flows counter current to the flow of the gas stream from the WSA process.

The source is proposing to install high efficiency mist eliminators and hydrogen peroxide (H_2O_2) scrubbers to control H_2SO_4 emissions from the process. These controls would be sufficient to comply with the sulfuric acid mist limit of the NSPS Subpart H, although, NSPS Subpart H does not apply to the project's WSA plant.

Subpart H regulates sulfuric acid production plants such as those that burn elemental sulfur. It does not regulate WSA units "*where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds*" (40 CFR 60.81(a)) such as the IG WSA plant. Nevertheless, the IG facility emissions will be at or below the Subpart H sulfuric acid mist limit of 0.15 lbs H_2SO_4 mist/ton of Acid produced. For practical purposes, all of the particulates from this source are this acid mist.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of the WSA (EU-015A/B).

(1) High efficiency mist eliminators and hydrogen peroxide (H_2O_2) scrubbers

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. For this source, the emissions of PM, PM_{10} and $PM_{2.5}$ equal those of H_2SO_4. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Wet Sulfuric Acid Plants (EU-015A/B)**	**10,400 T dry coal/day**	**0.15 lb/ton and 5 lbs/hour based on 3-hr average**	**High Effi. Mist Eliminator, H_2O_2 scrubber**
PSD-LA-742(M1)	Lake Charles Cogeneration, LLC	12/30/2010	Wet Sulfuric Acid Plants (2)*	9,413 T/D	0.15 lb/ton acid produced	High Effi. Mist Eliminator, H_2O_2 scrubber
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Sulfuric Acid Plants *	13,722 T coal per day	0.15 lb/ton, 0.06 lb/ton (24-hr) (permit lists two conflicting limits on different pages)	High Effi. Mist Eliminator, H_2O_2 scrubber

NOTE: * These emission units have not been built yet.

All three of the above facilities have designed their WSA plants with the best possible control - using similar technologies. All three facilities have a performance of 0.15 lb/tons acid produced. However, the Power Holdings of Illinois facility permit lists two conflicting emissions limits. In two places it lists 0.15 lb/ton acid produced, which is consistent with the NSPS standard and consistent with almost every other WSA in the RBLC (including those that burn elemental sulfur).

However, it also, separately lists an emission rate of 0.06 lb/ton H_2SO_4. Based on discussions with their WSA vendor, IG reports that there is not any confidence that the lower level of 0.06 lb/ton can be achieved. Also, the Power Holdings facility has not been built, and has not demonstrated this level of performance. Based on this information, this lower level is not an appropriate BACT precedent. Therefore, based on vendor input specific to IG, the lowest achievable rate for this source is proposed to be 0.15 lb/ton using H_2O_2 scrubbers and high efficiency mist eliminators. This equates to emissions of 5.0 lbs/hr for each WSA at design capacity.

It is noted that there are a few other sulfuric acid plants in the RBLC which are NSPS Subpart H applicable plants that burn elemental sulfur to produce sulfuric acid. BACT levels for these plants were also all set at 0.15 lb/ton of acid produced except for one facility which was permitted at 0.10 lb/ton. However, these types of plants are not appropriate for comparison to IG due to the process and equipment differences between the two operations. Plants that use elemental sulfur as their feedstock produce a smaller volume of tailgas for each per ton of sulfur produced – because the “feed” has virtually no diluents (i.e.; it is pure sulfur). In contrast, plants such as the IG facility, which burn acid gas streams with significant non-sulfur content, have higher volume tail gas streams per ton of sulfur produced. A higher tail gas flow rate results in higher mass emission of acid mist particulates at the same exhaust concentration.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for Wet Sulfuric Acid Plants (EU-015A/B).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.15 pounds per ton and 5 lb/hour, each, based on a 3-hr average.

Sulfuric Acid (H_2SO_4) BACT – Wet Sulfuric Acid Plants (EU-015 A and B)

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2S0_4) are particulates. Particulates are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Cyclones;

(2) Wet Scrubber;

(3) Electrostatic Precipitators (ESP);

(4) Fabric Filter Dust Collectors (Baghouses); and

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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

<u>Alternate Control Methods:</u>

One or more alternate methods of control may be considered when more cost-effective than conventional add-on controls or when conventional add-on control technology may not be feasible. For the H_2SO_4 sources from the proposed WSAs, the following alternate control methods were evaluated:

(1) Mist eliminators and Hydrogen peroxide (H_2O_2) scrubbers;

Step 2: Eliminate Technically Infeasible Options

(a) **Add-on Control Technology:** Add on control devices such as fabric filters and electrostatic precipitators (ESPs) are not suitable for wet condensable, corrosive acid mist. Based on availability and applicability, conventional particulate add-on control technology was eliminated from consideration due to technical infeasibility.

(b) **Mist eliminators and Hydrogen peroxide (H_2O_2) scrubber**
The final step in the WSA process involves absorbing and recovering the produced sulfuric acid. A small amount of sulfuric acid mist can carry out with the tail gas. To control these emissions, a high efficiency mist elimination filter is installed downstream of the hydrogen peroxide scrubber that captures 75 percent of the fine acid mist. This removal percentage is guaranteed by the equipment vendor. This is the most efficient mist filter available. While the peroxide scrubber that is located upstream of the mist eliminator is installed primarily to control SO_2, it is also estimated to remove 10% of the acid mist prior to the high efficiency mist eliminator filter. The peroxide scrubber uses a 50% hydrogen peroxide (H_2O_2) solution which flows counter current to the flow of the gas stream from the WSA process.

The source is proposing to install high efficiency mist eliminators and hydrogen peroxide (H_2O_2) scrubbers to control H_2SO_4 emissions from the process. These controls would be sufficient to comply with the sulfuric acid mist limit of the NSPS Subpart H, although, NSPS Subpart H does not apply to the project's WSA plant.

Subpart H regulates sulfuric acid production plants such as those that burn elemental sulfur. It does not regulate WSA units "*where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds*" (40 CFR 60.81(a)) such as the IG WSA plant. Nevertheless, the IG facility emissions will be at or below the Subpart H sulfuric acid mist limit of 0.15 lbs H_2SO_4 mist/ton of Acid produced.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of H2SO4 resulting from operation of the WSA (EU-015A/B).

(1) High efficiency mist eliminators and hydrogen peroxide (H_2O_2) scrubbers

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Wet Sulfuric Acid Plants (EU-015A/B)**	**10,400 T dry coal/day**	**0.15 lb/ton acid produced) and 5 lbs/hour based on 3-hr average**	**High Effi. Mist Eliminator, H_2O_2 scrubber**
PSD-LA-742(M1)	Lake Charles Cogeneration, LLC	12/30/2010	Wet Sulfuric Acid Plants (2)*	9,413 T/D	0.15 lb/ton acid produced	High Effi. Mist Eliminator, H_2O_2 scrubber
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Sulfuric Acid Plants *	13,722 T coal per day	0.15 lb/ton, 0.06 lb/ton (24-hr) (permit lists two conflicting limits on different pages)	High Effi. Mist Eliminator, H_2O_2 scrubber

NOTE: * These emission units have not been built yet.

All three of the above facilities have designed their WSA plants with the best possible control - using similar technologies. All three facilities have a performance of 0.15 lb/tons acid produced. However, the Power Holdings of Illinois facility permit lists two conflicting emissions limits. In two places it lists 0.15 lb/ton acid produced, which is consistent with the NSPS standard and consistent with almost every other WSA in the RBLC (including those that burn elemental sulfur). However, it also, separately lists an emission rate of 0.06 lb/T H_2SO_4. IG has indicated that based on discussions with their WSA vendor, there is not any confidence that this low of a limit can be achieved. Also, the Power Holdings facility has not been built, and has not demonstrated this level of performance. Based on this information, this lower level is not an appropriate BACT precedent. Therefore, based on vendor input specific to IG, the lowest achievable rate for this source is proposed to be 0.15 lb/T H_2SO_4 emissions rate using H_2O_2 scrubbers and high efficiency mist eliminators. This equates to emissions of 5.0 lbs/hr of H_2SO_4 for each WSA at design capacity.

It is noted that there are a few other sulfuric acid plants in the RBLC which are NSPS Subpart H applicable plants that burn elemental sulfur to produce sulfuric acid. BACT levels for these plants were also all set at 0.15 lb/ton of acid produced except for one facility which was permitted at 0.10 lb/ton. However, these types of plants are not appropriate for comparison to IG due to the process and equipment differences between the two operations. Plants that use elemental sulfur as their feedstock produce a smaller volume of tailgas per ton of sulfur produced – because the "feed" has virtually no diluents (it is pure sulfur). In contrast, plants such as the IG facility, which burn acid gas streams with significant non-sulfur content, have higher volume tail gas streams per ton of sulfur produced. A higher tail gas flow rate results in higher mass emission of acid mist at the same exhaust concentration.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for H_2SO_4 for Wet Sulfuric Acid Plants (EU-015A/B).

The H_2SO_4 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a high Efficiency Mist Eliminator and H_2O_2 scrubber and the H_2SO_4 emissions shall not exceed 0.15 pounds per ton acid produced and 5 lb/hour, each, based on a 3-hr average.

Carbon Monoxide (CO) BACT – Wet Sulfuric Acid Plants (EU-015 A and B)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Catalytic oxidation;

(c) Flares

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

The RACT/BACT/LAER (RBLC) Clearinghouse and review of other New Source Review (NSR) permits reveal that similar gas plants sources do not use any control device to control carbon monoxide emissions from the Wet Sulfuric Acid Plants.

Regenerative Thermal Oxidizers
The thermal oxidizer has a nigh temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of CO destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Emissions from emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. It is not known whether the acid mist in the WSA exhaust would poison the oxidation catalyst in this potential application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Wet Sulfuric Acid Plants at this source.

Flare
Although the CO concentration is very low, the stream flow rate is very high. The low heating value of the WSA stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is technically infeasible option for the Wet Sulfuric Acid Plants at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Regenerative Thermal Oxidizer - 99 % destruction efficiency

(2) Oxidation Catalyst - 75 % destruction efficiency

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Wet Sulfuric Acid Plants (EU-015A/B)**	**10,400 T dry coal/day**	**18.72 pounds per hour based on 3 - hour average, each**	**None**
PSD-LA-742(M1)	Lake Charles Cogeneration, LLC	12/30/2010	Wet Sulfuric Acid Plants (2)*	9,413 T/D	26.33 lbs/hr, each	Good design and proper operation
081801 AAF (Application	Power Holdings of	10/26/2009	Sulfuric Acid Plants *	13,722 T coal per	None	Good Air pollution

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
No. 07100063)	Illinois Gasification			day		control practices

NOTE: * These emission units have not been built yet.

Costs Effectiveness for use of RTO on the Wet Sulfuric Acid Unit Exhaust

Control Alternative	CO Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton CO	Other Impacts
RTO	0.8	79.2	$4,270,000	$488,000	$976,000	$12,300	Additional energy use & CO Emissions
Baseline	80.0	(proposed)					

Note: Source exhaust (cfm) = 122000
Thermal Oxidation Costs based on lower - range costs for control from USEPA fact sheet for regenerative Thermal Oxidizer (EPA-452/F-03-021)
$35.0 capital cost $/cfm
$4.0 operating cost $/cfm
$8.0 Annualized $/cfm
99% Control efficiency for CO (Assumed)

It is theoretically possible that further destruction of CO could be achieved with an add-on thermal or catalytic oxidizer. However, an add-on oxidation control technology would not be cost effective since the CO concentration in this stream is already low. A rough perspective of costs for an add-on oxidizer can be obtained using cost ranges from US EPA's Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021). It lists the range of annualized cost of a regenerative thermal oxidizer as $8 - $33 per cfm and a regenerative catalytic oxidizer as $11 to $41 per cfm. Since the WSA stack has a relatively large flow (even though it has a low concentration of CO), IG has conservatively assumed that the use of an oxidizer might have a cost at the lowest cost per cfm presented in this range ($8/cfm). Based on the WSA emissions rate of about 80 tons/yr CO and an exhaust flow rate of 122,000 cfm, the cost-effectiveness of controlling CO with an add-on oxidizer is conservatively estimated to be at least $12,300/ton. This is prohibitively expensive for a CO control device.

In addition, the use of a thermal or catalytic oxidizer for CO control will require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (particularly NO_x) which will at least partially offset any benefit of additional CO control.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Wet Sulfuric Acid Plants (EU-015A/B).

The CO emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall not exceed 18.7 pounds per hour based on 3 - hour average for each Wet Sulfuric Acid unit.

Sulfur Dioxide (SO_2) BACT - Wet Sulfuric Acid Plants (EU-015 A and B)

Step 1: Identify Potential Control Technologies

Sulfur dioxide (SO_2) can be controlled by the use of a scrubber. In many applications, the scrubber is either a FGD or a dry scrubber. In those applications, the SO_2 is reacted with lime, or limestone or caustic and converted to a sulfate or sulfite mixture which is managed as a sludge. In this application a peroxide based scrubber is proposed. With a hydrogen peroxide scrubber, the SO_2 is converted to H_2SO_4 and the waste stream is eliminated. A more conventional scrubber does not provide any improved efficiency and is therefore not reviewed in the subsequent steps.

Step 2: Eliminate Technically Infeasible Options

Peroxide Scrubber
The purpose of the Wet Sulfuric Acid unit is to recover sulfur that has been separated out of the syngas stream by the Acid Gas Recovery unit. It does this by converting the sulfur first to SO_2, then to sulfuric acid. The WSA is very efficient in this recovery process and its inherent design achieves a sulfur recovery of 99.977% to sulfuric acid. Inert gases and CO_2 in the unit are vented out the WSA stack and will contain a very small amount of SO_2. The proposed control for SO_2 from the WSA is a hydrogen peroxide scrubber. In the hydrogen peroxide scrubber, the gas stream from the WSA is scrubbed with a 50% solution of peroxide (H_2O_2). SO_2 is absorbed and converted to acid through a chemical reaction that takes place as follows:

$SO_2 + H_2O_2 = H_2SO_4$

The technology provider guarantees that 95% of the SO_2 in the gas stream will be removed in the peroxide scrubber. The SO_2 in the gas stream entering the scrubber is also minimized by inherent design of the WSA.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of peroxide Scrubber is a technically feasible option for the Wet Sulfuric Acid plants at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Peroxide Scrubber (95 % reduction of SO2)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Wet Sulfuric Acid Plants (EU-015A/B)**	**10,400 T dry coal/day**	**0.25 lb/ton acid produced and 8.3 pounds per hour, each (24-hr avg)**	**peroxide scrubber**
PSD-LA-742(M1)	Lake Charles Cogeneration, LLC	12/30/2010	Wet Sulfuric Acid Plants (2)*	9,413 T/D	0.5 lb/ton acid produced	Hydrogen peroxide scrubbing

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Sulfuric Acid Plants *	13,722 T coal per day	1.41 lb/ton, (30-day), 4.0 lb/ton NSPS limit 90 lb/hr and 342.4 tons per yr	SO2 Oxidation Catalyst and Hydrogen peroxide scrubbing

NOTE: * These emission units have not been built yet.

The Lake Charles Gasification Plant, was identified as having a non-elemental sulfur burning wet sulfuric acid plant. The RBLC shows the Lake Charles WSA SO_2 limit of 0.5 lb SO_2/Ton acid produced. This limit, for comparison, is well below the NSPS Subpart H limit of 4 lbs SO_2/Ton acid produced. A recently permitted facility, the Power Holdings of Illinois facility, is also proposing a similar WSA plant to the IG plant. The Power Holdings facility is permitted with an SO_2 emissions limits of 1.41 lb/T (30 Day) and 4.0 lb/T. Including sulfur-burning sulfuric acid plants, since 2006 there are a total of eight WSA plants in the RBLC with SO_2 emissions ranging from a low of 0.5 lb/ton SO_2 (Lake Charles) to a high of 3.0 lb/ton. SO_2 emissions from all facilities are controlled by scrubbing the tailgas with hydrogen peroxide.

Based on the RBLC review, a limit of 0.5 lbs SO_2 / ton acid produced is judged to be BACT. However, IG proposes to go beyond BACT to achieve SO_2 emissions of 8.3 lbs SO2/hr (equivalent to 0.25 lb/ton acid produced) for each WSA. This is being done to help demonstrate compliance with the SO2 National Ambient Air Quality Standards. This is lower than the Lake Charles RBLC limit, lower than indicated in Power Holdings permit, and lower than any other recent RBLC determination. Compliance with the lb/ton and lb/hr limits will be based on 24-hr block daily average because they are based on acid production rate which cannot be accurately calculated on an hourly basis.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO2 for Wet Sulfuric Acid Plants (EU-015A/B).

The SO_2 emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be controlled by a peroxide scrubber, the SO_2 emissions shall not exceed 0.25 lb/ton acid produced and 8.3 lbs SO_2/hr based on a 24-hour block daily average for each Wet Sulfuric Acid unit.

Nitrogen Oxide (NO_X) BACT - Wet Sulfuric Acid Plants (EU-015 A and B)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR)

(c) Flue Gas Recirculation (FGR)

(d) Low NOx Burner (LNB)

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750 F. Temperatures below the optimum decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Selective Non-Catalytic Reduction (SNCR)

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction.

At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the source exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Low NOx Burner (LNB)

Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and fuel, as well as other methods that effectively lower the flame temperature. In the drive to reduce NOx emissions, NOx reduction techniques were implemented to lower peak flame temperature.

The LNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a staged air combustion LNB, either air or fuel is added downstream of the primary combustion zone. Depending on which of this NOx reduction technique is used, LNBs with staged combustion are subdivided into staged air burners and staged fuel burners.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one burner installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible especially when other NOx reduction technique is used in conjunction with LNBs.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a low NOx burner is a technically feasible option for the Wet Sulfuric Acid Plants at this source

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR can lower NOx emissions on two ways; the cooled, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reaction for one of the ingredients they need.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flue Gas Recirculation (FGR) is a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following control technologies have been identified for control of NOx resulting from operation of the Wet Sulfuric Acid Plants. The source has chosen SCR as their control for NOx emissions and no further analysis will be performed on the remaining less effective control devices.

(1) Selective Catalytic Reduction — (up to 90% NOx Reduction)

(2) Selective Noncatalytic Reduction (50% NOx Reduction)

(3) Low NOx Burner (LNB) — (40% — 50% NOx Reduction)

(4) Flue Gas Recirculation (FGR) — (25% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Wet Sulfuric Acid Plants (EU-015A/B)**	**10,400 T dry coal/day**	**10.2 lb/hr NO_x based on 24-hr block daily average,**	**Selective Catalytic Reduction**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
					each	
PSD-LA-742(M1)	Lake Charles Cogeneration, LLC	12/30/2010	Wet Sulfuric Acid Plants (2)*	9,413 T/D	14.305 pounds per hour (each)	Selective Catalytic Reduction
081801 AAF (Application No. 07100063)	Power Holdings of Illinois Gasification	10/26/2009	Sulfuric Acid Plants *	13,722 T coal per day	11.0 pounds per hour and 38.6 tons per yr	Selective Catalytic Reduction

NOTE: * These emission units have not been built yet.

NO_x emissions are created during the combustion of acid gases in the WSA Plant. There are a number of WSA facilities in the RACT/BACT/LAER Clearinghouse, but only one, the Lake Charles Gasification Facility, lists the use of any add-on control technology. The Lake Charles facility lists selective catalytic reduction (SCR) for NO_x emissions with a permitted NO_x emission rate of 13.5 lb/hr maximum emissions from each of its two WSA units. Indiana Gasification is also proposing to use SCR for control of NO_x emissions from the WSA at an emissions rate of 10.2 lb/hr from each WSA. Both IG and Lake Charles have the same emission rate for NOx based on the vendor supplied NOx lb/ton acid produced emissions factor. The IG WSA vendor indicates that 10.2 lb/hr is the lowest achievable emissions rate for this facility.

Therefore, IG is proposing BACT for this source to be 10.2 lb/hr NOx (24-hr block daily average) from each WSA using SCR control technology when the flow to the SCR at or above a temperature of 750 degrees F. While IG is proposing a 24-hour average, the Lake Charles Gasification Facility has a one-hour limit. The Lake Charles permit indicates that compliance will be based on a stack test whereas IDEM is requiring that IG install a NOx CEMS on this unit. IDEM believes that the use of CEMS to determine compliance for 24-hour periods is a more stringent compliance requirement for a source with an SCR unit than a stack test with the average of three one-hour runs being used to determine compliance and, therefore, has determined that the IG limit is equivalent or more stringent than the Lake Charles limit due to the method of compliance determination.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Wet Sulfuric Acid Plants (EU-015A/B).

The NOx emissions from the Wet Sulfuric Acid Plants (EU-015A/B) shall be limited by the use of a selective catalytic reduction (SCR) when the flow to the SCR is at or above a temperature of 750 degrees F and the NOx emissions shall not exceed 10.2 pounds per hour NOx based on a 24-hour block daily average for each Wet Sulfuric Acid unit.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – ASU and Main Cooling Tower (EU-016A and 016B)

Step 1: Identify Potential Control Technologies

Emissions of Particulate matter (PM, PM_{10} and $PM_{2.5}$) from cooling towers are generally controlled by a drift elimination system.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the PM/PM10/PM2.5 emissions from the Cooling Tower.

Drift Elimination System

Cooling towers are a source of particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate ($PM/PM_{10}/PM_{2.5}$) emissions once the water mist evaporates. To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Particulate matter emissions occur from cooling towers when suspended solids contained in water used in the cooling tower becomes airborne as the water is circulated and cooled. Drift eliminators contain packing which is used to limit the amount of this particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a drift elimination system is technically feasible option for the Main Cooling Tower and ASU Cooling Tower at this source.

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 towers at this source is the use of high efficiency drift eliminators designed to 0.0005% maximum drift to maintain a drift loss as well as 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 PM, PM_{10} and $PM_{2.5}$ BACT determination along with other PM, PM_{10} and $PM_{2.5}$ BACT determinations for cooling towers. All data in the table is based on the information obtained from 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.

Existing $PM/PM_{10}/PM_{2.5}$ BACT Limits – Cooling Tower

Company Name / Operation	RBLC ID	Date of Permit	Control Technology & Compliance Methods and BACT Limit
Indiana Gasification - *proposed* – Draft Permit No. 147-30464-00060 Proposed Limit	N/A	N/A	**High efficiency drift eliminators designed to 0.0005% maximum drift**
Gainesville Renewable Energy Center	FL-0323	12/28/2010	0.0005% Drift
Warren County Biomass Energy	GA-0141	12/17/2010	0.0005% Drift
Specialty Minerals Inc. – Superior	WI-0252	7/22/2010	0.0005% Drift
Wolf Hollow Power Plant #2	TX-0552	3/3/2010	0.0005% Drift
Panda Sherman Power LLC	TX-0551	2/3/2010	0.0005% Drift
Power Holdings of Illinois	N/A	10/26/2009	0.0005% Drift
Lake Charles Gasification	LA-0231	12/30/2010	0.0005 % Drift

USEPA’s RACT/BACT/LAER Clearinghouse shows BACT determinations specifying the use of drift/mist eliminators for controlling PM, PM_{10} and $PM_{2.5}$ emissions, with drift rates ranging from 0.003% – 0.0005%. A design drift rate of 0.0005% appears in the most recent permit determinations and it represents the best performing of all cooling towers in the RBLC and the highest efficiency mist eliminators available in the cooling tower design. Additionally, cooling tower particulate can be reduced by effective management of the total dissolved solids (TDS) content in the cooling water. IG has indicated that the TDS level in the cooling water will be monitored and maintained at a no more than 1500 ppm TDS based on a daily average by adjustment of the cooling tower blowdown (purge) rate.

Proposal: Indiana Gasification, LLC, Rockport, IN

The following has been proposed as BACT by for PM, PM_{10} and $PM_{2.5}$ emissions from the ASU Cooling Tower EU-016A and Main Cooling Tower EU-016B operations:

Therefore, a 0.0005% drift/mist eliminator system along with a maximum TDS of 1500 ppm based on a daily average is proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from both the Main and ASU Cooling Towers.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM, OAQ has approved the proposed PM, PM_{10} and $PM_{2.5}$ BACT for the ASU Cooling Tower EU-016A and Main Cooling Tower EU-016B.

The PM, PM_{10} and $PM_{2.5}$ emissions from the ASU Cooling Tower (EU-016A) and the Main Cooling Tower (EU-016B) shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005% and total dissolved solids shall not exceed 1500 ppm based on a daily average.

Sulfuric Acid (H_2S0_4) BACT – Sulfuric Acid Tanks (EU-027A - F)

Step 1: Identify Potential Control Technologies

Emissions of Sulfuric Acid (H_2S0_4) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Cyclones;

(2) Wet Scrubber;

(3) Electrostatic Precipitators (ESP);

(4) Fabric Filter Dust Collectors (Baghouses); and

(5) Cartridge Collectors.

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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Alternate Control Methods:
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 Sulfuric Acid (H2S04) emission sources at the proposed Gas Plant, the following alternate control methods were evaluated:

(1) Fixed roof tanks with a pressure/vacuum vent and submerged fill pipes

Step 2: Eliminate Technically Infeasible Options

These control alternatives are further described as follows.

(a) **Add-on Control Technology:** Add on control devices such as fabric filters, electrostatic precipitators (ESPs), and scrubbers are not technically feasible for this source's very low PM emission rates(<0.001 ton/yr). Based on availability and applicability, add-on control technology was eliminated from consideration due to technical infeasibility.

(b) **Fixed roof tanks with a pressure/vacuum vent and submerged fill pipes**
The sulfuric acid tanks will have very little acid mist emissions (<0.001 ton/yr, for each tank). The tanks vent will be fitted with a pressure/vacuum control and the fill pipe shall be placed below the normal liquid level (submerged fill pipe). The vent should open to the atmosphere only as needed when the tank is up-gauging – to relieve the displaced vapors. The sulfuric acid tanks will be equipped with a nitrogen blanket which is necessary to keep oxygen and moisture out of the tanks. The nitrogen blanket is designed to keep a slight pressure on the vacuum vent and is not designed as a nitrogen “sweep”. The nitrogen blanket does not cause or change the emissions of H_2SO_4 from the tanks.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of H_2SO_4 resulting from operation of the Sulfuric Acid tanks (EU-027A-F).

(1) Fixed roof tanks with a pressure/vacuum vent and submerged fill pipes.

Step 4: Evaluate the Most Effective Controls and Document the Results

The sulfuric acid storage tanks are fixed roof tanks with a Pressure Vacuum (PV) vent. This is standard storage technology for low vapor pressure materials, less than about 1 psia. The vapor pressure of the sulfuric acid is extremely low (less than 0.001 psia) at maximum ambient conditions, so any vapor releases will be very small (estimated emissions from all sulfuric acid tanks are 0.0011 tons/yr.) Also, because of the very small emissions rate and dilute concentration, add-on controls such as a “mist eliminator” would not be effective.

The tanks also will operate with a nitrogen “blanket”. This means that when the tank level drops, that nitrogen will be introduced to fill the new vapor space rather than letting air be drawn in through the PV vent. This is to avoid tank corrosion or fire hazards from air in the tank. This inert “blanket” is not a nitrogen “sweep”, and will not increase emissions from the tank.

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for H_2SO_4 from the proposed Sulfuric Acid tanks at the Indiana Gasification Plant.

BACT for H_2SO_4 is proposed to be a fixed roof tank and submerged fill.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for H_2SO_4 for the Sulfuric Acid tanks.

The H_2SO_4 emissions from the Sulfuric Acid tanks shall be limited by the use of a fixed roof tank and submerged fill.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – ZLD Spray Dryer (EU-032)

Step 1: Identify Potential Control Technologies

Emissions of PM, PM_{10} and $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In the case of a spray dryer, the material being dried is entrained and the control of PM is coincident with the recovery of dried material. Generally, PM, PM_{10} and $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Cyclones;

(2) Wet Scrubber;

(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.

Step 2: Eliminate Technically Infeasible Options

(a) **Cyclones:**
Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs. Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is a technically feasible option for the spray dryer associated with the Zero Liquid Discharge (ZLD) at this source.

(b) **Wet Scrubber**
A wet scrubber is an air pollution control device that removes particulates from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulates. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulates size decreases.
Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulates with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);

(2) Combustible, corrosive and explosive materials;

(3) Particles that are difficult to remove in their dry form;

(4) Particulates in the presence of soluble gases; and

(5) Particulates in waste gas streams with high moisture content.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is a technically feasible option for the collection of material from the spray dryer associated with the Zero Liquid Discharge (ZLD) at this source.

(c) **Electrostatic Precipitators:**
An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 99% to 99.9%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an Electrostatic Precipitator is a technically feasible option for the collection of PM from the spray dryer associated with the Zero Liquid Discharge (ZLD) at this source.

(d) **Fabric Filtration:**
A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting.

Typical values of system pressure drop range from about 1 to 20 inches of water. Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system.

The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a fabric filter is a technically feasible option for the control of PM from the spray dryer associated with the Zero Liquid Discharge (ZLD) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from operation of the Spray dryer associated with the Zero Liquid Discharge (ZLD) Spray Dryer.

(1) Fabric Filtration (99% - 99.9% PM/PM_{10}/$PM_{2.5}$ Reduction)

(2) Electrostatic Precipitator (99% - 99.9% PM/PM_{10}/$PM_{2.5}$ Reduction)

(3) Wet Scrubber (99% PM/PM_{10}/$PM_{2.5}$ Reduction)

(4) Cyclones (80% PM/PM_{10}/$PM_{2.5}$ Reduction)

Both the Electrostatic Precipitator and the Fabric Filtration have the same control efficiencies, 99% - 99.9%. The source has selected the Fabric Filtration for this unit which is the highest efficiency alternative.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with other PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar but larger spray dryers. All data in the table is based on the information obtained from 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.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method	Estimated Control Efficiency
Draft Permit No. 147-30464-	**Indiana Gasification - *proposed***	**Proposed**	**ZLD spray dryer**	**5.6 MMBtu/hr**	**0.005 gr/dscf**	**Baghouse**	**Not specified**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method	Estimated Control Efficiency
00060 Proposed Limit							
OK-0118	Western Farmers Electric Coop Hugo Generating Station	2/9/2007	Wastewater (brine) spray dryer	20 MMBtu/hr	PM10: 0.20 lb/hr	Good combustion control	Not specified
OK-0111*	Dal Italia LLC Muskogee Porcelain Floor Tile Plant	10/14/2005	Spray Dryers	49.1 MMBtu/hr	PM10: 0.018 gr/dscf	Baghouse	Not specified
AZ-0046	Arizona Clean Fuels Yuma	4/14/2005	Spray Dryer Heater	44 MMBtu/hr	PM10: 0.0075 lb/MMBTU	Not specified	Not specified
OH-282	Cargill Oilseeds Division	11/28/2003	Isolate Plant Soy Protein Spray Dryer	114 MMBtu/hr	PM10: 0.003 gr/dscf; 4.68 lbs/hr; 20.5 tons per rolling 12 months	Baghouse and separation cyclone	Not specified

*BACT/LAER clearinghouse for this determination lists a PM10 limit of 0.0.017 gr/dscf and an estimated efficiency of 99.0%. The above PM10 limit is from the permit 2004-198-C (M-1).

One of the listed BACT limits is lower than what has been proposed by IG. However, this unit is drying soy protein rather than inorganic salt and thereby, the particle characteristics and size distributions are not comparable. In addition, this unit is 20 times larger (in firing rate) than the IG spray dryer. Therefore, this lower grain loading number is not a relevant precedent for this BACT determination.

Proposal: Indiana Gasification, LLC, Rockport, IN

The following has been proposed as BACT by for PM, PM_{10} and $PM_{2.5}$ emissions from the Zero Liquid Discharge (ZLD) operations:

(1) A fabric filter baghouse.
(2) The PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.005 gr/dscf based on 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM, OAQ has established PM, PM_{10} and $PM_{2.5}$ BACT for the Zero Liquid Discharge (ZLD) Spray Dryer:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Zero Liquid Discharge (ZLD) spray dryer shall be controlled by a fabric filter baghouse and the PM, PM_{10} and $PM_{2.5}$ emissions shall not exceed 0.005 gr/dscf based on a 3 hour average.

Carbon Monoxide (CO) BACT – ZLD Spray Dryer (EU-032)

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by combustion control or add on oxidation systems. Such add-on control technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;

(b) Catalytic oxidation;

(c) Flares

(d) Combustion Control

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer is a high temperature process maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. The ignition occurs at some point during the heating of a waste stream as it passes through the combustion chamber. The mixture continues to react as it flows through the combustion chamber.

The level of CO destruction within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{o}F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.
Regenerative Thermal Oxidizers achieve high thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed). The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, now feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Emissions from emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Flare

The low heating value of the spray dryer exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of process stream.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is a technically infeasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Combustion Control

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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Combustion Control is a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Regenerative Thermal Oxidizer - 99 % destruction efficiency

(2) Oxidation Catalyst - 75 % destruction efficiency

(3) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with other CO BACT determinations for similar but lager spray dryers. All data in the table is based on the information obtained from 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.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating**	**Limitation**	**Control Method**	**Estimated Control Efficiency**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**5.6 MMBtu/hr**	**5.6 MMBtu/hr**	**0.036 lb/MMBtu**	**Good Combustion**	**Not specified**
OK-0118	Western Farmers Electric Coop Hugo Generating Station	2/9/2007	Wastewater (brine) spray dryer	20 MMBTU/hr	0.70 lb/hr	Good combustion control	Not specified
OK-0111*	Dal Italia LLC Muskogee Porcelain Floor Tile Plant	10/14/2005	Spray Dryers	49.1 MMBT/hr	13.77 lb/hr	Good combustion	Not specified
AZ-0046	Arizona Clean Fuels Yuma	4/14/2005	Spray Dryer Heater	44 MMBTU/hr	0.04 lb/MMBTU	Not specified	Not specified
LA-0184	Louisiana Pigment Company Titanium Dioxide Facility	5/13/2003	Spray Dryer Dust Collectors	25.5 MMBTU/hr	2.31 lb/hr	Good equipment design and proper combustion techniques.	Not specified

*BACT/LAER clearinghouse for this determination lists a CO limit of 0.23 lb/ton and an estimated efficiency of 99.5%, but this information could not be found in the permit. The above information is from the permit 2004-198-C (M-1).

This review indicates that the proposed limit is consistent with recent BACT determinations for similar

Costs Effectiveness for use of RTO on Zero Liquid Discharge Dryer

Control Alternative	CO Emissions Tons/yr	Emissions Reduction tons/yr	Control Capital Cost $	Control Operating Cost $/yr	Total Annualized Costs $/yr	Cost Effectiveness $/Ton CO	Other Impacts
RTO	0.0089	0.8811	$233,800	$16,700	$55,110	$62,500	Additional energy use & CO Emissions
Baseline	0.9	(proposed)					

Note: Source exhaust (cfm) = 1670

Thermal Oxidation Costs based on lower - range costs for control from USEPA fact sheet for regenerative Thermal Oxidizer (EPA-452/F-03-021)
$140.0 capital cost $/cfm
$10.0 operating cost $/cfm
$33.0 Annualized $/cfm
99% Control efficiency for CO (Assumed)

It is theoretically possible that further destruction of CO could be achieved using an add-on thermal or catalytic oxidizer. However, an add-on oxidation control technology would not be cost effective since the CO concentration and overall emissions in this stream is already low. A rough perspective of costs for an add-on oxidizer can be obtained using cost ranges from US EPA's Air Pollution Control Technology Fact Sheet for Regenerative Incinerators (EPA-452/F-03-021). It lists the range of annualized cost of a regenerative thermal oxidizer as $8 - $33 per cfm and a regenerative catalytic oxidizer as $11 to $41 per cfm. Since the ZLD dryer is an extremely small combustion source, it has been assumed that the use of an oxidizer might have a cost at the higher end of the cost per cfm range for an RTO ($33/cfm). Based on the WSA emissions rate of about 0.89 tons/yr CO and an exhaust flow rate of 1670 cfm, the cost-effectiveness of controlling CO with an add-on oxidizer is estimated to be at over $60,000/ton. This cost is clearly excessive for CO BACT.

Besides the cost issues, use of a thermal or catalytic oxidizer for CO control will require the use of a significant amount of supplemental fuel (to heat the exhaust gas to the required operating temperature to achieve destruction). This supplemental fuel firing will create additional combustion pollutant emissions (especially NOx) which will at least partially offset any benefit of additional CO control.

Proposal: Indiana Gasification, LLC, IN

The following has been proposed as BACT for CO from the proposed Zero Liquid Discharge (ZLD) Spray Dryer;

(1) Good Combustion Practices

(2) Emission limitation of 0.036 lb/MMBtu of CO based on 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Zero Liquid Discharge (ZLD) Spray Dryer.

The CO emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.036 lb/MMBtu and shall use good combustion practices.

Sulfur Dioxide (SO_2) BACT - ZLD Spray Dryer (EU-032)

Step 1: Identify Potential Control Technologies

Emissions of Sulfur dioxide (SO_2) from gas fired spray dryers such as the Zero Liquid Discharge (ZLD) Spray Dryer proposed here are generally not controlled. Much larger sources of SO_2 are generally controlled by;

1. Flue Gas Desulfurization

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing SO_2 emissions from the Zero Liquid Discharge (ZLD).

The test for technical feasibility of any control option is whether it is both available and applicable to reducing SO_2 emissions from the gas-fired Zero Liquid Discharge (ZLD) Spray Dryer.

Flue Gas Desulfurization (FGD) System (Wet or Dry Scrubber)
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent.

Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2. FGD systems are listed in the RBLC as BACT for sources high in SO_2 emissions. Even though the SO_2 concentrations in the exhaust gases are very low, and the airflow volume is large, the scrubbing systems are technically feasible. Wet scrubbing FGD system is considerably cheaper than dry scrubbing.

SO_2 emissions result only from the trace levels of sulfur present in the small amount of natural gas or SNG used. Clean natural gas combustion exhaust contains less than 2 ppm $SO_{2.}$ This is too low for any add-on control technology such as a wet scrubber to be feasible. Wet scrubbing systems are typically only installed on exhaust streams of coal and oil fired units, with an inlet pollutant loading of approximately 250 - 2000 ppm SO_2. In the very best cases, wet scrubbing systems can achieve up to as high as 98% control and reduce SO_2 to single digit ppm levels. However, this vent is already less than 2 ppm SO_2 (because of the clean fuel used).

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flue gas desulfurization system (FGD) is not a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the SO2 emissions resulting from the Zero Liquid Discharge (ZLD) Spray Dryer.

Step 4: Evaluate the Most Effective Controls and Document the Results

No BACT determinations for SO_2 from Spray Dryers were located in the RBLC data base. Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the SO_2 emissions resulting from the Zero Liquid Discharge (ZLD) spray dryer.

Proposal: Indiana Gasification, LLC, - Rockport, IN

The following has been proposed as BACT for SO_2 from the proposed Zero Liquid Discharge (ZLD) Spray Dryer;

(1) The use of a clean burning gaseous fuel.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO2 for Zero Liquid Discharge (ZLD) Spray Dryer.

The SO_2 emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall be limited through the use of a clean burning gaseous fuel.

Nitrogen Oxide (NO_X) BACT - ZLD Spray Dryer (EU-032)

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the followings:

(a) Selective Catalytic Reduction (SCR)

(b) Selective Non-Catalytic Reduction (SNCR)

(c) Flue Gas Recirculation (FGR)

(d) Low NOx Burner (LNB)

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 500°F to 1100°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. Temperatures below the optimum decrease catalyst activity and allow NH_3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

The Zero Liquid Discharge (ZLD) Spray Dryer emits less than 1.0 ton per year of NOx emissions. The burner size for the ZLD spray dryer is 5.6 MMBtu/hr total. The spray dryer will fire natural gas during startup operations and fire SNG during normal operations. The baseline emission level of NOx from this size burner is sufficiently low that no further, quantifiable emission reduction would be achieved by add-on technologies.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Low NOx Burner (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air and fuel, as well as other methods that effectively lower the flame temperature. In the drive to reduce NOx emissions, NOx reduction technique were implemented to lower peak flame temperature and oxygen availability.

The LNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a stage air combustion LNB, either air or fuel is added downstream of the primary combustion zone.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one burner installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible especially when other NOx reduction technique is used in conjunction with LNBs.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Low NOx Burner is a technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be an effective technique for lowering NOx emissions from burners.

Most of the early FGR work was done on boilers, and investigators found that recirculating up to 25% of the flue gases through the burner could lower NOx emissions to as little as 25% of their normal levels. FGR can lower NOx emissions on two ways; The cooled, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reaction for one of the ingredients they need.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Flue Gas Recirculation (FGR) is technically feasible option for the Zero Liquid Discharge (ZLD) Spray Dryer at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The above control technologies have been identified for control of NOx resulting from operation of the Zero Liquid Discharge (ZLD). Based on the technical feasibility analysis in Step 2, the source has chosen Low NOx Burner (LNB) as their control for NOx emissions and no further analysis will be performed on the remaining control devices.

(1) Low NOx Burner (LNB) — (40% — 50% NOx Reduction)

(2) Flue Gas Recirculation (FGR) — (25% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with other NOx BACT determinations for similar but spray dryers. All data in the table is based on the information obtained from 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.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating**	**Limitation**	**Control Method**	**Estimated Control Efficiency**
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**ZLD Spray Dryer**	**5.6 MMBtu/hr**	**0.035 lb/MMBtu**	**Low NOx burners.**	
AZ-0046	Arizona Clean Fuels Yuma	4/14/2005	Spray Dryer Heater	44 MMBTU/hr	0.03 lb/MMBTU	Low NOx burners	Not specified
OH-282	Cargill Oilseeds Division	11/28/2003	Isolate Plant Soy Protein Spray Dryer	114 MMBTU/hr	0.065 lb/MMBTU ; 7.41 lbs/hr; 32.46 tons per rolling 12 months	Low NOx burners	Not specified

A review of the RBLC indicates that the best control for NOx emissions from such a source is the use of low NOx burners (LNB). It is noted that one of the past BACT determinations has a slightly lower emission rate limit. However, that unit is eight times larger. It is recognized that low NOx burner technology can be more sophisticated and effective with larger units. Therefore, the limit proposed by IG is consistent with and in comparison to prior BACT determinations

Proposal: Indiana Gasification, LLC, IN
The following has been proposed as BACT for NOx from the proposed Zero Liquid Discharge (ZLD) Spray Dryer;

(1) The use of a Low NOx Burner

(2) Emission limitation of 0.035 lb/MMBtu of NOx based on a 3 hour average.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for Zero Liquid Discharge (ZLD) Spray Dryer.

The NOx emissions from the Zero Liquid Discharge (ZLD) Spray Dryer shall not exceed 0.035 lb/MMBtu and shall use a Low NOx Burner (LNB).

Sulfur Dioxide (SO_2) BACT - Fugitive Leaks from piping (FUG & FUG-WSA)

Step 1: Identify Potential Control Technologies

The SO2 emissions from fugitive leaks can be controlled by;

(a) Leak detection and Repair (LDAR)

Step 2: Eliminate Technically Infeasible Options

There are small amounts of SO_2 emissions from fugitive leaks from equipment and pipe components such as pumps, valves, flanges and compressors. IG plans to implement a Leak Detection and Repair (LDAR) program on select streams. Specifically, LDAR is proposed for the piping components in VOC service (methanol & propylene) and for WSA piping in SO_2 service. The selected LDAR program is primarily for the purpose of controlling organic HAPs and VOC. Additionally, SO_2 is being controlled in the section of WSA piping between the combustor and oxidation.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(a) Leak Detection and Repair (LDAR)

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC – Rockport, IN

The following has been proposed as BACT for SO_2 from the Fugitive Leaks from Equipment (FUG and FUG-WSA).

The BACT for fugitive leaks of SO_2 in the WSA is proposed as the use of a Leak Detection and Repair (LDAR) program.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO2 for the Fugitives Leaks from piping (FUG and FUG - WSA).

The BACT for the fugitive leaks of SO_2 in the WSA is the use of a Leak Detection and Repair (LDAR) program.

CO and H_2SO_4 BACT - Fugitive Leaks from piping (FUG & FUG-WSA)

Step 1: Identify Potential Control Technologies

The emissions such as CO and H_2SO_4 from fugitive leaks can be controlled by;

(a) Leak detection and Repair (LDAR)

(b) No Controls

Step 2: Eliminate Technically Infeasible Options

There is a very small amount of emissions of CO and H_2SO_4 from fugitive leaks from equipment and pipe components such as pumps, valves, flanges and compressors. The source plans to implement a Leak Detection and Repair (LDAR) program on select streams. Specifically, LDAR is proposed for the piping components in VOC service (methanol & propylene). The selected LDAR program is primarily for the purpose of controlling organic HAPs and VOC. The use of an LDAR program to control CO or H_2SO_4 would be extremely unusual and would require use of different instrumentation than a conventional organic LDAR program. Consequently, IG has not proposed use of LDAR for the other syngas or WSA acid gas streams.

The table below shows the typical expected concentration of each of the main process streams from the IG facility that contain non-trace levels of CO and H_2SO_4 and the very small amount of their emissions from the facility.

Table 1

Concentrations of Pollutants in each Process Stream			
	BACT Pollutants		**Other Pollutants**
Process Streams	**CO**	**H2SO4**	
Raw Syngas	20.4%		H2S, COS
Shifted Syngas	3.7%		H2S, COS
Mixed Syngas	14.8%		H2S, COS
Sweet Syngas	22.5%		H2S, COS
Acid Gas		3.6%	H2S, COS, SO2
Fugitive Emissions	**tons/yr**	**tons/yr**	
Total Uncontrolled	9.45	0.09	
Note: Compounds not listed for a stream are negligible for that stream			

Note: The above streams are all included in the IG facility emissions estimates. Fugitive Equipment Leaks designated as emissions unit “FUG” reflect emissions of syngas streams as well as the methanol and propylene streams. The acid gas streams are included in Fugitive Equipment Leaks from the WSA designated as “FUG-WSA”.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(a) Leak Detection and Repair (LDAR)

(b) No control (for CO and H_2SO_4)

Step 4: Evaluate the Most Effective Controls and Document the Results

Given the low concentration of CO and H_2SO_4 in the process streams, the relatively low fugitive emissions rate of these pollutants, and the fact that use of an LDAR program for these pollutants would be unusual, the use of an LDAR program eliminated from BACT consideration.

Proposal: Indiana Gasification, LLC – Rockport, IN

The following has been proposed as BACT for CO and H_2S0_4 from the Fugitive Leaks from Equipment (FUG and FUG-WSA).

(1) The BACT for fugitive leaks of CO and H_2SO_4 is proposed as no-controls.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO and H_2S0_4 for the Fugitives Leaks from piping (FUG and FUG - WSA).

(1) The BACT for fugitive leaks of CO and H_2SO_4 is no-controls.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$) BACT – Fugitive Dust From Paved Roads (FUG-ROAD)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and $PM_{2.5}$ from fugitive sources are generally controlled with measures to prevent the emissions from occuring. Generally, fugitive PM, PM_{10} and $PM_{2.5}$ emissions from roadways are controlled through one of the following mechanisms:

(1) Paving of Roadways
(2) Wet Suppression or Chemical suppression
(3) Good Housekeeping (cleanup spilled material)

Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP’s are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device.

Step 2: Eliminate Technically Infeasible Options

<u>Add-on Control Technology:</u>
Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP’s are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device.

Wet Suppression or Chemical suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Suppression or Chemical suppression is a technically feasible option for the Plant Haul Roads (FUG-ROAD) at this source.

Paving Roadways and Good Housekeeping
Paving all haul roads and prompt cleanup of any spilled or eroded materials are effective at minimizing dust emissions from vehicle traffic.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.

2. Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

3. Particulate emission from paved roadways can also be minimized with good housekeeping, i.e. cleaning up spills of solid material or dirt eroded onto the road surfaces.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for related operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Haul Road fugitive dust from vehicle traffic**	**10,400 T dry coal/day**	**90% control**	**Wet or Chemical Suppression**
LA-0240	FLOPAM, Inc	06/14/2010	Roadway Fugitives	Not Specified	0.04 lb/hr	BACT for road dust is to pave roadways where practicable. Unpaved roads shall utilize water spray or dust suppression chemicals and speed limits of 15 mph on unpaved road.
KY-0100	East Kentucky Power Coop.	04/09/2010	Haul Roads	Not Specified	Not Specified	Paved Roadways Cleaning or promt removal of material, and the application of wet suppression as applicable
OH-0332	Sun Coke Energy	2/9/2010	Roadways and Parking areas	Not Specified	PM 1.08TPY	Control measures (Watering etc) when necessary.
OH-0317	Ohio River Clean Fuels	11/20/2008	Raodways and parking areas	736 KVMT/yr	15.39 tpy PM10	Reduce Speed Limit, Sweeping, Watering and good Housekeeping measures.

The table above shows recent entries in the RACT/BACT/LAER Clearinghouse (RBLC) database for Haul Roads. The proposed control level of 90% is the highest specified in the RBLC for such sources. Some BACT determinations specify reduced speed as part of their control strategy. Given the short in-plant distances, nature of the roadways, and the large vehicle sizes, the source haul vehicles will naturally travel at low speeds in the IG plant.

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Plant Haul Road at the Indiana Gasification Plant.

BACT for PM, PM_{10} and $PM_{2.5}$ for the Fugitive Dust from Plant Haul Roads (FUG-ROAD) is proposed to be:

1. Paving all plant haul roads,
2. Use of wet or chemical suppression for control by 90%,
3. Prompt cleanup of any spilled materials.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Fugitive Dust from Plant Haul Roads (FUG-ROAD).

The PM, PM_{10} and $PM_{2.5}$ emissions from the paved road (FUG-ROAD) shall be controlled by 90 % by the use of:

1. Paving all plant haul roads,
2. Use of wet or chemical suppression
3. Prompt cleanup of any spilled materials.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Front-End Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C)

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM) and particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and PM2.5 are generally controlled with controls designed to prevent or 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, PM and PM_{10} emissions are controlled through one of the following mechanisms:

(1) Wet Suppression or Chemical suppression;

(2) Filtration;

- (a) Baghouse;
- (b) Wet Extraction System;

(3) Other Add-on Controls (cyclone, ESP).

Step 2: Eliminate Technically Infeasible Options

The slag pile operations cannot reasonably be enclosed and vented to a control device due to the potential size of the pile and its location outside. This eliminates the applicability of collection and filtration equipment or other add-on controls.

The only remaining controls for this material handling that is technically feasible for these sources is wet or chemical suppression. Frequent use of water or chemical surfactants can significantly reduce airborne dust from these types of open material handling operations. This is the most commonly utilized control for these types of sources.

Wet Suppression or Chemical suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Suppression or Chemical suppression is a technically feasible option for the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Wet Suppression or Chemical suppression (up to 90% PM, PM_{10} and $PM_{2.5}$ Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for relevant operations. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 147-30464-00060 Proposed Limit	**Indiana Gasification - *proposed***	**Proposed**	**Slag Pile Operations**	**10,400 T dry coal/day**	**90% control**	**Wet or Chemical Suppression**
IA-0089-Iowa	Homeland Energy Solutions	08/08/2007	Coal Receiving and handling	200 tons/hr	None specified for unenclosed unloading area	water fogging to eliminate particulate in unloading area
IA-0086-Iowa	Homeland Energy Solutions	05/03/2007	Coal Pile	50,565 tons/hr	PM/PM10: Must use dust suppressant to reduce fugitive emissions by 95%	Chemical dust Suppressant with 95% control
CO-0057 - Colorado	Public Service Company of Colorado Comanche Station	07/05/2005	Coal handling and storage (includes open storage piles with lowering well, rail-car unloading, transfer from unloading to pile and	NA	None specified for unenclosed unloading area	Control include water spray, lower well, dust suppressant, enclosures where

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
			transfer from pile to bunker)			baghouse are not feasible
KY-0100	East Kentucky Power Coop.	04/09/2010	Coal Pile, Rail Unloading Egress to Conveyor	3000 tons per hr	10% opacity (3min)	Wet Suppression, Dust suppressant Lowering well and compaction
OH-0317	Ohio River Clean Fuels	11/20/2008	Coal Storage Piles	5500 tons/hr	PM10:12.3 tons per year. with 75% control.	3-sided windscreen barrier. Reduced drop heights. Use of chemical stabilization dust suppressants and/or watering to reduce any visible emissions.

NOTE: * These emission units have not been built yet.
Note: ** Compliance with the limit at this facility has not been demonstrated through stack testing.

The table above shows recent entries in the RACT/BACT/LAER Clearinghouse (RBLC) database for material handling activities that can't be enclosed. All these permits specify wet or chemical suppression, consistent with the source's proposal. Although most of the database entries do not specify the level of control, two of the listed entries specify 75% and 95%. Dependent on the amount and frequency of the application of wet suppression, various levels of control can theoretically be achieved by wet suppression. Control of greater than 90% is not normally considered practicable.

(a) **Proposal**: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C):

(1) A Wet Suppression or Chemical suppression providing 90% control efficiency.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Front-end Loader Slag Handling (EU-034A) and Vehicle Dust on Slag Pile (EU-034C) shall be controlled by a Wet Suppression or Chemical suppression with 90% control efficiency.

Greenhouse Gases (GHG) BACT – RTOs (EU-007A/B)

Step 1: Identify Potential Control Technologies

The acid gas removal (AGR) units remove CO_2 from the syngas and produce a stream which is 98% pure CO_2. This stream will be compressed to a liquid and sold. Whenever it is instead vented, it will be sent to one of two Regenerative Thermal Oxidizers (RTOs), one serving each AGR. The RTOs will oxidize small amounts of CO, COS, methane and VOCs (methanol) in the vent gas.

The heating value of the CO_2 stream to be vented is very low because it contains mostly non-combustible CO_2. As a result, supplemental fuel is required to maintain the RTO at its operating temperature, when it is in standby and during its operation, to sustain the necessary temperature for oxidation to occur. As such, it is both a control device and a source of emissions.

The RTOs will be fired with SNG or natural gas. The amount of fuel that is needed is minimized by the units' design. RTOs provide heat recovery and reduce the fuel needed to control emissions of trace components in this stream. A conventional thermal oxidizer would also be technically feasible for this stream. It is estimated that a conventional thermal oxidizer would require more than ten times the supplemental fuel required for an RTO. Therefore, RTOs are technically feasible, they will reduce supplemental fuel use and, thereby, reduce the associated emissions of CO_2. The use of the RTOs will increase the CO_2 emissions of this vent slightly (about 1% versus direct venting). This is due primarily to the conversion of trace quantities of CO, COS, methane, and methanol in this stream to CO_2 during the combustion process. Although the RTO slightly increases CO_2 emissions, its use is appropriate to reduce the emissions of other compounds as is further discussed in the BACT analysis for CO for the AGR vent.
This analysis focuses on the emissions of CO2 only. While other GHGs, such as methane and N2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources such as the RTOs. To the extent measures are identified that reduce fuel use and thereby CO2, the other GHGs will be reduced accordingly. Therefore, CO2 serves as a useful surrogate for other GHGs in this regard.

The source is proposing to use a regenerative thermal oxidizer (RTO) that is fired with SNG and natural gas. An RTO is the most energy efficient technology that could be used in this service. No higher level of control for CO_2 emissions has been identified.

(1) No Control

Step 2: Eliminate Technically Infeasible Options

No technically feasible measures have been identified to control CO_2 emissions associated with the operation of the RTOs.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no viable control technologies for the control of CO_2 emissions from the RTO.

Step 4: Evaluate the Most Effective Controls and Document the Results

No technically feasible measures have been identified to control CO_2 emissions associated with the operation of the RTOs.

Step 5: Select BACT

No technically feasible measures have been identified to control GHG emissions associated with the operation of the RTOs.

Greenhouse Gases (GHG) BACT – Acid Gas Recovery (AGR) Unit Vent (EU-007A/B)

Step 1: Identify Potential Control Technologies

This analysis focuses on the emissions of CO2 only. While other GHGs are present in trace quantities, there are no known add on control technologies for these pollutants coming from this kind of source. To the extent measures are identified that reduce CO2 emissions, the other GHGs will be reduced accordingly. Therefore, CO2 serves as a useful surrogate for other GHGs in this regard. One option was identified for this source:

1. Sequestration of the AGR Vent CO_2.

Step 2: Eliminate Technically Infeasible Options

Sequestration of the AGR Vent CO_2

In any situation when the sale of liquefied CO_2 via the pipeline will not occur, geological sequestration in lieu of venting has been considered.

In EPA's recent guidance on GHG BACT EPA has taken the position that capture and sequestration of CO_2 as an add-on pollution control technology is 'available' for "large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams . . . ." In particular, EPA cites the report of the Interagency Task Force on Carbon Capture and Storage for the proposition that "current technologies could be used to capture CO_2 from new and existing fossil energy power plants . . ."

IDEM does not necessarily agree that sequestration must be considered to be 'available.' However, because this BACT analysis concludes that sequestration is technically infeasible, the BACT determination is not affected by that designation and, therefore, the remainder of this analysis will presume sequestration to meet the criteria as an 'available' technology.

In Step 2 of the top-down BACT process, a permit applicant is instructed to analyze all "available" and "applicable" control technologies. Control technologies that are "available" but not "applicable" are not technically feasible for the project and need not further be analyzed. EPA defines an "applicable" control technology as follows:

> EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful

> operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.

The volume of CO_2 that may be emitted from the AGR vent, though a small percentage of the CO_2 to be delivered as product to the product pipeline over the life of the facility, is a critically important aspect of whether sequestration is “applicable” to the proposed plant. Accordingly, EPA states that:

> CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components [capture and/or compression, transport, and storage] from what has already been applied to a differing source type . . . [or] if the three components working together are deemed technically infeasible for the proposed source taking into account the integration of the CCS components with the base facility and site-specific considerations . . . .

EPA identifies four elements to consider when assessing whether there exist “significant differences,” “integration,” and “site-specific characteristics” that might lead a permitting authority to a finding of inapplicability of sequestration: (1) whether the proposed project has access to or can develop a suitable sequestration site; (2) whether government funding will be required to implement transportation or sequestration solutions; (3) whether the timing of access to or construction of CO_2 transportation infrastructure is consistent with the proposed project; and (4) whether contracts or rights of way for offsite land use for transportation and storage will be required. After considering these factors, “a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs [is] determined to be generally available from commercial vendors.” IDEM has addressed each of these elements and concluded that sequestration is inapplicable to this project for the disposition of CO_2 that will otherwise be vented.

Access to or development of a suitable sequestration site. The source has neither access to, nor can develop, a suitable sequestration site for the volume of CO_2 that may be vented from the AGR vents. As indicated above, there is an ongoing potential to emit 1,290,000 tons/yr of CO_2 from the AGR vents. This venting is not predictable even on a daily or weekly basis. Rather such venting will occur intermittently.

While sequestration is being studied for use in the region where the plant will be located, there is presently no practical option. Department of Energy (DOE) funding is currently supporting a substantial research and demonstration initiative called the Regional Carbon Sequestration Partnership (RCSP) program. This program is just now beginning several large-scale CO_2 injection research projects targeting injection of over 1 million tons of CO_2 (a scale that is about the same as would be needed by the IG facility). In the Illinois Basin where IG’s project is located, the regional partnership is the Midwest Geologic Sequestration Consortium (MGSC). That group has a large-scale sequestration demonstration underway at the ADM plant in Decatur, Illinois (about 200 miles from Rockport). That project expects to inject 1 million tons of CO_2

beginning in 2011 to “further understanding of carbon sequestration technology around the world.” The results of this demonstration won’t be known for some time.

FutureGen 2.0 is a DOE supported power plant project in Illinois that will incorporate carbon capture and develop geologic sequestration. Part of the plan for FutureGen 2.0 is the development of a regional sequestration site where CO_2 from the FutureGen project, and potentially other projects, could be stored. FutureGen issued an RFP for proposed sites and identified four finalist locations in Illinois. The site is to be designed to accept at least 1.3 million metric tons of CO_2 per year over 30 years (the amount expected to be captured by the FutureGen plant), but could be expanded at some point in the future to accept additional CO_2 from other power plant or industrial facilities.

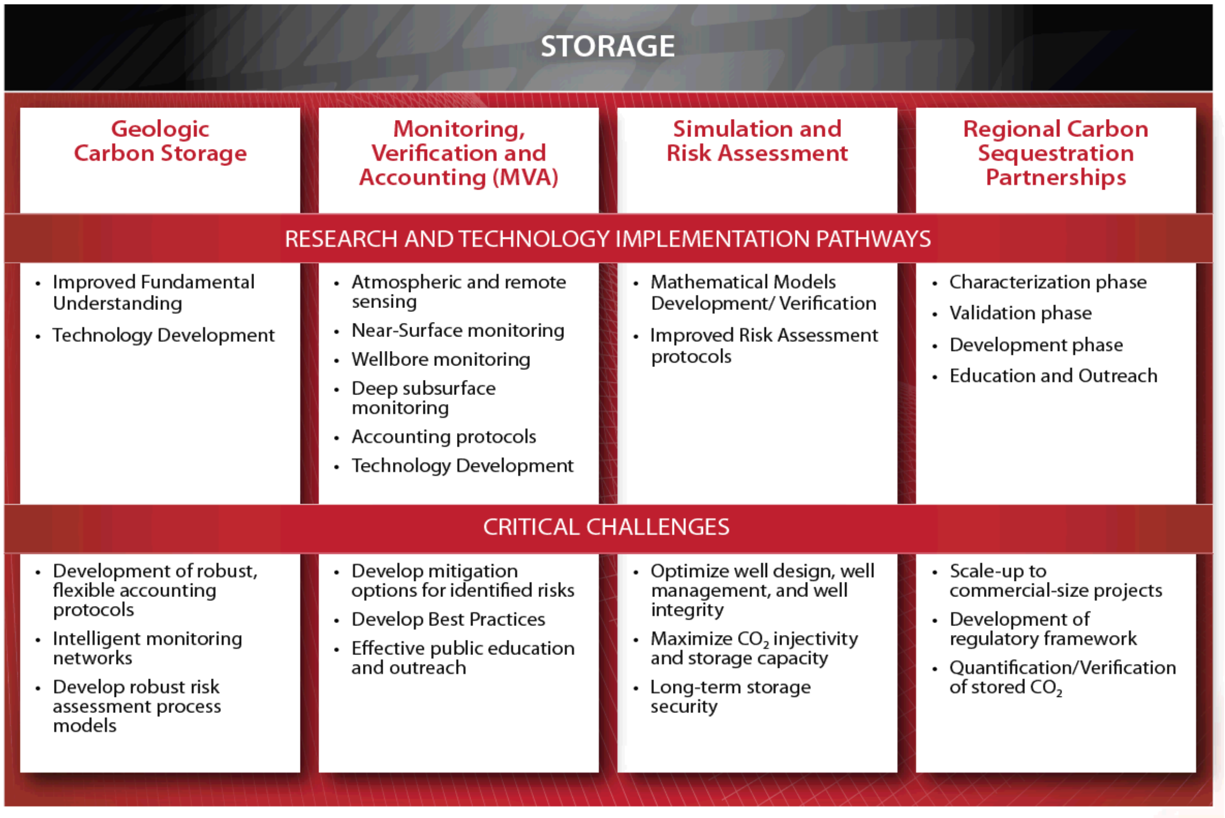
On February 28, 2011, FutureGen 2.0 announced the tentative selection of a site in Morgan County, IL. However, selecting this site merely begins the process of further geologic characterization and it triggers the beginning of the environmental review required under the National Environmental Policy Act (NEPA) that will afford opportunities for public participation and comments. Given the unprecedented nature of the proposed sequestration, many technical and legal issues remain to be addressed including the public acceptability of the proposed site. These issues make the ultimate development of this site uncertain. It is also not clear whether or by how much it will be sized to accept CO_2 beyond that produced by the FutureGen power plant, what criteria will be used to determine who can potentially use the site for CO_2 storage, or when the site might actually be completed and begin CO_2 storage operations. The FutureGen 2.0 initiative does not represent an available sequestration site for the IG facility.

Another carbon injection demonstration closer to Rockport is in Hancock County, Kentucky across the Ohio River from Indiana Gasification’s site. That project, being conducted by the Kentucky Geologic Survey with funding from Kentucky and DOE, drilled an 8,216 foot well and injected 18,454 barrels of brine and 323 tons of CO_2 in 2009. Limited information is available regarding the results of this research, but the small scale of the injection—a total CO_2 injection that was less CO_2 than the Indiana Gasification project will produce every hour—makes clear that significant additional research is needed to demonstrate the viability of large-scale sequestration in this region.

The necessity of government funding for CCS infrastructure. As summarized below, significant and sustained government research will be required for many years to develop a reliable and accessible sequestration infrastructure that will accommodate the volume of CO_2 emitted from the AGR vent. The government research and development is needed to address the many critical challenges of applying many geologic sequestration options.

The DOE National Energy Technology Laboratory (NETL) issued a Carbon Dioxide Capture and Storage R&D Roadmap in December 2010. The NETL report outlines critical challenges to carbon storage technology (see following figure) and outlines a research initiative that runs through 2025 for developing needed technologies and understanding. This RD&D roadmap makes clear that geologic sequestration is an important research initiative of the federal government and that CCS has many risks without significant additional government research, development and demonstration of sequestration methods.

Figure F-1 from DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap



STORAGE

Geologic Carbon Storage	Monitoring, Verification and Accounting (MVA)	Simulation and Risk Assessment	Regional Carbon Sequestration Partnerships
RESEARCH AND TECHNOLOGY IMPLEMENTATION PATHWAYS			
• Improved Fundamental Understanding • Technology Development	• Atmospheric and remote sensing • Near-Surface monitoring • Wellbore monitoring • Deep subsurface monitoring • Accounting protocols • Technology Development	• Mathematical Models Development/ Verification • Improved Risk Assessment protocols	• Characterization phase • Validation phase • Development phase • Education and Outreach
CRITICAL CHALLENGES			
• Development of robust, flexible accounting protocols • Intelligent monitoring networks • Develop robust risk assessment process models	• Develop mitigation options for identified risks • Develop Best Practices • Effective public education and outreach	• Optimize well design, well management, and well integrity • Maximize CO_2 injectivity and storage capacity • Long-term storage security	• Scale-up to commercial-size projects • Development of regulatory framework • Quantification/Verification of stored CO_2

Timing of and access to available transportation infrastructure. IDEM is unaware of any CO_2 transportation infrastructure—aside from the EOR pipeline contemplated for use by this project—that would have the capacity to transport the volume of CO_2 emitted by the AGR vent to a sequestration site, in any timeframe relevant to the commencement of operation of the facility.

Acquisition of land for transportation infrastructure. The logistical challenges of constructing a second pipeline as a “backup” to the EOR pipeline make this option infeasible. First, the fact that any pipeline infrastructure would only be used when liquefied CO_2 is not sold for EOR, a circumstance the project will take steps to avoid, means any pipeline constructed will lay idle most of the time. Second, and more important, to make a second pipeline available, IG would need to establish a pipeline route, find right of way opportunities, and then construct whatever pipelines would be needed to transport CO_2 for sequestration, all in light of the fact that there will not exist in the near future any suitable sites for the sequestration of CO_2 from the facility. Moreover, IDEM cannot today identify where pipeline infrastructure should be built and, therefore, cannot even begin the process of trying to engineer or build it.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of sequestration of the AGR vent is not a technically feasible option for the Acid Gas Recovery Unit Vent at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, there are no viable control technologies for the control of GHG emissions from the Acid Gas Recovery Unit Vent.

Step 4: Evaluate the Most Effective Controls and Document the Results

In its review of the RACT/BACT/LAER Clearinghouse (RBLC) and similar permits, no facilities were identified where controls were required for an Acid Gas Recovery (AGR) Vents.

The acid gas removal (AGR) units remove CO_2 from the syngas and produce a stream which is 98% pure CO_2. This stream will be compressed to a liquid and sold. It will be transported to the Gulf Region where it will be used in Enhanced Oil Recovery (EOR) operations.

IG expects to be the first project designed to supply CO_2 to the Gulf Coast EOR market from a coal-based facility in the Midwest. There are, however, certain challenges to producing and selling CO_2 product. In particular, a pipeline is needed to transport the CO_2 from the plant site to the Gulf Region. No such pipeline currently exists. The present implementation plan for the project would finance the pipeline coincident with financing of the gasification project. IG will not begin construction of this facility without a fully financed project agreement for the pipeline that provides for the pipeline to be in place and ready to receive liquefied CO_2 at the point when pipeline quality CO_2 is available. It is in IG's interest to have the pipeline available for shipments as early as possible, as IG will receive significant income from the sale of CO_2. Nevertheless, IG cannot be 100% certain that the pipeline will be operating and ready to receive CO_2 at the time the IG facility begins operation.

A number of factors may lead to delays in the construction and operation of the pipeline:

1. Building this pipeline, which will run several hundred miles through several states, will require securing many rights-of-way and obtaining numerous federal, state, and local approvals. Delays in this approval process may also extend the pipeline schedule.

2. At present, the pipeline arrangement contemplates serving only the IG facility. However, other parties are considering the production and sale of CO_2 to the same market. Therefore, as this project goes forward, it may become economically beneficial and appropriate under developing regulatory programs to change the plans for the pipeline to accommodate one or more other CO_2 producers in the region. Doing this may result in a change in the capacity and route of the pipeline and may delay the current schedule.

While the greatest risk of delay relates to the pipeline being ready, securing and meeting the requirements of customers for the CO_2 may also cause a delay in shipping CO_2, even if the pipeline is ready to receive CO_2.

1. A customer committed to purchasing IG's CO_2 may need to build and commission new CO_2 infrastructure which may create delays in the sale of CO_2 for the customer.
2. There may be delays as shipping schedules for the various customers are sorted out.

On those occasions when CO_2 is not sold as product, the CO_2 is vented from the AGRs. The CO_2 stream will first be directed to a regenerative thermal oxidizer (RTO) to oxidize small amounts of methane, VOCs (methanol), H_2S, CO and COS that are present in it. Because the RTOs will combust SNG or natural gas to support oxidation of these trace components, the RTOs are both control devices and emissions sources. As a result, a separate GHG BACT review of the fuel used in the RTO has been completed.

In light of the difficulties of plant start up and the potential for a delay in the start of shipments of CO_2 through the pipeline from this facility to the CO_2 customers, IG is anticipating that CO_2 emissions at the facility may be higher in the first two years than for the remaining project life. Over the life of the project most of the CO_2 will be sold and shipped to the Gulf Region for EOR use.

With the nature of facility start up and the risk of a pipeline delay, the source is proposing different limits on the CO_2 emissions from the AGR/RTO vents for each of the first two years of operation, and a different, lower limit that will be applicable thereafter.

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for GHG from the proposed Acid Gas Recovery (AGR/RTO) Vents:

1. The proposed limit for the first year of operation is 4.69 million tons. This figure reflects the impact of startup on operating rates and resulting CO_2.

2. The second year, IG proposes a limit of 6.43 million tons, which is reflective of the permitted capacity of the plant.

3. The proposed limit thereafter is 1.29 million tons per year, starting with the third year of operation. After the third full year, it would apply on a 12-month rolling basis, with compliance determined at the end of each month, based on the total of the prior 12 months.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Acid Gas Recovery (AGR/RTO) Vents.

(1) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 4,690,000 tons of CO_2 during the first 12 months of operation.

(2) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 6,430,000 tons of CO_2 during the second 12 months of operation.

(3) The CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1, 290,000 tons of CO_2 during the third 12 months of operation.

(4) Thereafter, the CO_2 emissions from the Acid Gas Recovery (AGR) Vents shall not exceed 1,290,000 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of each month.

Greenhouse Gases (GHG) BACT – Wet Sulfuric Acid Plants (EU - 015A/B)

Step 1: Identify Potential Control Technologies

This analysis focuses on the emissions of CO2 only. While other GHGs, such as methane and N2O, may be present in trace quantities due to upstream combustion processes, there are no known add on control technologies for these pollutants coming from WSAs. To the extent measures are identified that reduce CO2, the other GHGs may be also reduced accordingly. Therefore, CO2 serves as a useful surrogate for other GHGs in this regard when a measure reduces the overall discharge from this source. Three options were identified for this source:

(1) No Control;

(2) Recycling the WSA stack gas back to the AGR (which would require pure oxygen use in the WSA combustor instead of air); and

(3) Carbon (CO_2) Capture in WSA Tailgas.

Step 2: Eliminate Technically Infeasible Options

No Control
Most of the CO_2 in the WSA exhaust comes from the Acid Gas Recovery (AGR) units as a constituent in the acid gas stream. The AGR generated acid gas is the feed to the WSA unit. Through its inherent design, the AGR unit will remove at least 90% of the CO_2 in the syngas for liquefaction and sale.

This percent capture results from the relative solubilities of CO_2, COS and H_2S in the Rectisol solution and by the need for the AGR unit to be designed and optimized to balance its three critical AGR operating requirements: 1) assuring SNG product quality; 2) assuring liquid CO_2 product quality; and 3) assuring acceptable acid gas quality to the WSA.

The high CO_2 capture in the AGR incidentally results in relatively modest levels of CO_2 in the acid gas stream to the WSA. WSA emissions of CO_2 are estimated to not exceed 474,000 tons per year at maximum design rates. This is approximately 7% of the syngas CO_2 at maximum design. Below is a further brief discussion of how the AGR captures CO_2, H_2S and COS.

Cold methanol is used to physically absorb CO_2, H_2S and COS at high pressures. Absorption in the methanol solvent for each compound is affected by its concentration, the methanol solvent temperature and pressure, and the compounds relative solubility in methanol. The CO_2, H_2S and COS are significantly more soluble than other syngas components (CO, H_2, CH_4, and N_2). This solubility difference allows CO_2, H_2S and COS to be removed from the syngas in the AGR systems. However, their similar solubility makes it difficult to separate the H_2S, COS, and CO_2 from each other.

H_2S, COS, and CO_2 are removed from the loaded methanol solvent when it is depressurized because they are less soluble at lower pressures and higher temperatures. Among these compounds, H_2S and COS are more soluble than CO_2. To achieve effective separation, the loaded methanol solvent is depressurized in multiple stages – at progressively lower pressures.

After an initial pressure reduction to flash off any absorbed syngas product, CO_2 is next flashed out of the solvent (in three stages) generating what becomes the facility's liquefied product CO_2 stream (98% pure). In a final step, the methanol solvent, having been stripped of more than 90% of its CO_2, is then heated in a hot regenerator, to strip out the H_2S and COS. The sulfur-rich acid gas stream from the regenerator, which is then sent to the WSA, will also contain some remaining CO_2. It is very difficult to further reduce the CO_2 content of the acid gas stream because of the relatively close solubility of the acid gases and CO_2.

Because of this inherently efficient AGR system, baseline emission from the WSA will be modestly low, even without additional controls.

Recycling WSA Tailgas

Recycling WSA tailgas back to the AGR to recover the CO_2 using the existing/expanded AGR unit was identified as a theoretical option to reduce GHG emissions. If this were possible, it could reduce or eliminate WSA CO_2 emissions. However, this option is not commercially demonstrated and is not considered technically feasible as discussed below.

The major technical hurdle to recycling WSA tail gas back to the inlet of the acid gas unit (AGR) is the fact that it contains a high nitrogen content (approximately 79% by volume) This nitrogen comes from the use of air for the combustion of H_2S and COS necessary for the production of sulfuric acid. If this tail gas stream were recycled to the AGR, this nitrogen would contaminate/dilute the product SNG. The resulting SNG would contain greater than 40% nitrogen, which would not meet product quality specifications for its sale and use. The only potential remedy would be to use pure oxygen in place of air in the WSA. While theoretically possible, IDEM knows of no instance where 'oxyfiring' of a WSA has never been done, and it would involve a number of significant technical challenges. Given that it has not been done in WSA service, and is not commercially offered, the use of pure oxygen and recycle of the WSA is considered technically infeasible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of pure oxygen and recycle is not a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Carbon (CO_2) Capture in WSA Tailgas

Another theoretical option is capturing the CO_2 in the WSA exhaust in a separate solvent scrubbing system (not the AGR Rectisol system). Such a control would, theoretically, be similar to post-combustion carbon capture systems as are beginning to be contemplated for consideration for large fossil-fuel fired power plants. Although the WSA tail gas is not the product of conventional fuel combustion, from a CO_2 capture perspective it has similar technical and economic issues to those of post-combustion carbon capture for a medium sized industrial boiler.

The following highlights the similarities between the WSA tailgas and a typical boiler exhaust.

(1) Low CO_2 concentration – The WSA tail gas exhaust will contain about 6.6% CO_2 concentration. This is on the lower end of the range of the typical exhaust concentrations for natural gas boilers which range from 6-9% CO_2.

(2) Low Pressure – The WSA tail gas is at atmospheric pressure as are boiler exhaust stacks.

(3) Low quantity of CO_2 – The annual CO_2 emissions from each WSA unit are orders of magnitude smaller than are emitted from large fossil-fuel fired power plants and concentrated industrial CO_2 sources for which carbon capture is being considered. For example, each WSA has the CO_2 equivalent emissions of a boiler of only about 360 MMBTU/hr.

The post-combustion carbon capture of CO2 from the Auxiliary Boilers is discussed elsewhere in this document and determined to not be an applicable and available control option because of the low CO_2 concentration, low exhaust pressure and limited CO_2 available for capture (i.e.: small size of the Aux boilers). For these same reasons, carbon capture of the CO_2 in the exhaust of the WSA units is not an applicable and available technology.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon capture of CO_2 is not a technically feasible option for the Wet Sulfuric Acid Plants at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the GHG emissions resulting from the Wet Sulfuric Acid; however, emissions will be inherently low due to the highly efficient design of the proposed facility

Step 4: Evaluate the Most Effective Controls and Document the Results

In its review of the RACT/BACT/LAER Clearinghouse (RBLC) and similar permits, no facilities were identified where controls for CO2 were required on the Wet Sulfuric Acid Plant.

Proposal: Indiana Gasification, LLC
The following limit has been proposed for CO_2 from the proposed Wet Sulfuric Acid:

The WSA CO2 emissions shall be limited to 474,000 tons per year, as a rolling 12-month total.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Wet Sulfuric Acid Plant.

The CO_2 emissions from the Wet Sulfuric Acid Plant operation shall not exceed 474,000 tons per year as a rolling 12-month total.

Greenhouse Gases (GHG) BACT – Auxiliary Boilers (EU-005A/B)

Step 1: Identify Potential Control Technologies

(1) Use of low-carbon gaseous fuel (NG or SNG);

(2) Energy efficient boiler design (features considered: inlet air controls, economizer, condensate recovery, and blowdown heat recovery); and

(3) Post-combustion CO_2 capture.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

Step 2: Eliminate Technically Infeasible Options

Low Carbon Fuel

Carbon dioxide (CO_2) is a product of combustion generated with any carbon-containing fuel. The preferential use of natural gas (or substitute natural gas), a low-carbon fuel, is a method of lowering CO_2 emissions versus use of solid or other fuels available at the IG site. The table below illustrates the CO_2 emission factors for combustion of a variety of fuels.

Typical CO_2 Emission Factors

Fuel	Pounds CO_2 per Million Btu
Petroleum Coke*	225
Coal**	210
Distillate Oil**	161
Natural Gas (or SNG)*	117

* Source GHG MRR Rule, Subpart C, Table C-1
**Source: US Energy Information Administration,
http://www.eia.doe.gov/oiaf/1605/coefficients.html

The IG Project auxiliary boilers will fire natural gas/SNG as a low-carbon fuel, despite the fact that coal is available on the site.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of low carbon fuel is a technically feasible option for the Auxiliary Boilers at this source.

Boiler Energy Efficiency

Another opportunity for reducing GHG emissions is to increase the energy efficiency of the boilers. Because CO_2 emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required and the less greenhouse gas emissions that result. (Note: Auxiliary boiler firing is also reduced through the high degree of heat-integration of the overall process which reduces supplementary steam requirements.)

Specific energy efficiency measures that may be applied to boilers include the following:

Inlet air controls (such as O_2 monitor and inlet air flow control) limit excess air. Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process. An oxygen monitor and control of inlet air will be included in the IG auxiliary boilers design. This measure helps assure ongoing optimization of the boiler tuning. This, along with a NO_x emissions limits and continuous emissions monitor required by NSPS Db, will help keep the boilers tuned for efficient operation (making periodic boiler tuning unnecessary).

Heat Recovery of heat in the stack gas can be accomplished with either an economizer or an air preheater. An economizer recovers this heat by preheating boiler feed water. This reduces the heat energy required from fuel combustion to generate steam. An air preheater uses this heat to preheat the combustion air, thereby decreasing fuel firing requirements. The source will use an economizer, but will not use an air preheater because there is insufficient heat available in the stack gas to do both types of heat recovery.

Condensate Recovery returns the hot steam condensate from the process as feedwater, thereby decreasing the boiler heat load. All of the IG process steam condensate and condensed steam from the steam turbine generator are combined and preheated to 250ºF in the low temperature gas cooling section of the plant after CO Shift conversion. This is the source of feedwater for the boilers.

Recover Heat from the Blowdown is accomplished by sending blowdown water from the boiler steam drum to a low pressure flash drum. The pressure drop in the flash drum produces low pressure steam which is captured and used in the process by low pressure steam users. Further recovery of the small amount of residual heat in the condensate is not practical.

The combination of these measures is expected to result in a thermal efficiency, when at full design rate, of at least 81% (HHV basis).

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of energy efficiency is a technically feasible option for the Auxiliary Boilers at this source.

Post-combustion CO_2 Capture

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* However, the IG auxiliary boilers do not fit into either of these categories. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers appears in its guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option. The IG Project auxiliary boilers, with combined average annual utilization of 172 MMBTU/hr, are smaller than this EPA example.

Based on EPA's guidance, a CO_2 capture system for small to medium size combustion systems, such as the IG auxiliary boilers, is not a reasonable BACT option. This is understandable because the capture of the CO_2 from the IG auxiliary boiler exhaust is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four predominant factors: the auxiliary boiler exhaust's low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the high variability of load for these two boilers.

CO_2 Capture Difficulty

Natural gas combustion boiler exhaust streams have relatively low CO_2 concentrations (6-9% versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams). This means that for a natural gas boiler a very large volume of gas needs to be treated to recover the CO_2. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any natural gas combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. The average annual firing rate of the auxiliary boilers of 172 MMBTU/hr is less than 1/20th the size of a typical fossil fuel fired power plant boilers that EPA contemplates having to consider the potential for CCS. Additionally, rapid swings in the load of this auxiliary boiler would complicate use of post-combustion capture.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion CO_2 capture is not a technically feasible option for the Auxiliary Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling GHG emissions from the Auxiliary Boilers.

(1) Use of low-carbon gaseous fuel (natural gas or SNG); and
(2) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)

Step 4: Evaluate the Most Effective Controls and Document the Results

In its review of the RACT/BACT/LAER Clearinghouse (RBLC) and similar permits, no facilities were identified where CO_2 controls were required on Auxiliary Boilers.

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for GHG from the proposed Auxiliary Boilers:

(1) Use of low-carbon gaseous fuel (natural gas or SNG); and
(2) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)
(3) Boiler designed for 81% thermal efficiency (HHV).
(4) An annual limit on the CO_2 emissions of the boilers, combined, of 88,167 tons per year.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHGs for the Auxiliary Boilers.

(1) Use of natural gas or SNG;

(2) Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery.)

(3) Boiler designed for 81% thermal efficiency (HHV);

(4) The total CO_2 emissions from the auxiliary boilers shall not exceed 88,167 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Greenhouse Gases (GHG) BACT – Syngas Hydrocarbon Flare (EU-001)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare Greenhouse Gases (GHG) emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel and flare combustion and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and operating are key elements in emissions performance of flares. However, Greenhouse Gases (GHG) emissions are not greatly affected by flare design. Instead, flare Greenhouse Gases (GHG) are primarily a function of the amount of material flared. The open-flame nature of a flare results in inherently good Greenhouse Gases (GHG) performance (the oxidation of any methane) and prohibits the use of design features.

The source is proposing the use of elevated flares. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented gases. A potential alternative flare design is an enclosed or ground flare. However, enclosed flares are not typically considered for high flow rate situations Nevertheless, regardless of the type of flare used, there are no flare design or operational features were identified as applicable for Greenhouse Gases (GHG) control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Flare design and proper operation is not a technically feasible way to control GHGs from the Syngas Hydrocarbon flare at this source.

Process flaring minimization practices (including operating procedures in the Flare Minimization Plan
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of Greenhouse Gases (GHG) will be less. Flaring minimization practices are feasible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Process flaring minimization practices is a technically feasible option for the control of GHG emissions from the Syngas Hydrocarbon flare at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the IG facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.

(2) Another significant difference is that refineries can recover flare gas into their fuel gas cleanup system which operates at less than 100 psig. In contrast, the IG facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor versus those at refineries.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Flare gas recovery is not a technically feasible option for the control of GHG emissions from the Syngas Hydrocarbon flare at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technology for flares is:

(1) Process flaring minimization practices (Flare Minimization Plan)

Process flaring minimization practices (Flare Minimization Plan)
There are a number of steps that can be taken in the operation of the facility that will reduce the volume of gases flared and thereby the emissions of particulates. During a planned shutdown of a gasifier, the contents of the gasifier (gasifier vessel, quench chamber, scrubber vessel) can be routed, during initial depressurization, to one of the Wet Sulfuric Acid (WSA) plants. Also, the feed rate to the gasifiers can be reduced such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare. Also, the permittee can investigate the "root cause" of malfunction events that cause gases to be sent to the flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC – Rockport, IN

Process flaring minimization practices (Flare Minimization Plan)

Features of the IG facility design that affect the ultimate use of the flares include the following:

A. The permittee shall comply with the following Flare Minimization Plan to reduce GHG emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for Greenhouse Gases (GHG) for Syngas Hydrocarbon Flare (EU-001) and Acid Gas Flare (EU-002).

A. The permittee shall comply with the following Flare Minimization Plan to reduce GHG emissions during startups, shutdowns, and other flaring events.

During a planned shutdown of a gasifier, the permittee shall route the contents of each gasifier unit (gasifier vessel, quench chamber, scrubber vessel) during initial depressurization to one of the Wet Sulfuric Acid (WSA) plants.

The permittee shall reduce gasifier feed rates such that all syngas can be processed through one gas treatment train prior to a scheduled gas treatment train outage. This limits the amount of syngas that will have to be sent to the syngas hydrocarbon flare.

In addition, the permittee shall have written procedures for the above operations and the permittee shall train the operators on these procedures.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Greenhouse Gases (GHG) BACT –Acid Gas Flare (EU-002)

Step 1: Identify Potential Control Technologies

In evaluating BACT for flare Greenhouse Gases (GHG) emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBLC, as well as other permits and sources, the list of potential control and process alternatives includes the following:

(1) Flare design and proper operation;

(2) Process flaring minimization practices (Flare Minimization Plan); and

(3) Flare gas recovery.

This analysis focuses on the emissions of CO_2 only. While other GHGs, such as methane and N_2O, are present in trace quantities, there are no known add on control technologies for these pollutants coming from combustion sources. To the extent measures are identified that reduce fuel and flare combustion and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs in this regard.

Step 2: Eliminate Technically Infeasible Options

Flare design and proper operation
Flare design and operating are key elements in emissions performance of flares. However, Greenhouse Gases (GHG) emissions are not greatly affected by flare design. Instead, flare Greenhouse Gases (GHG) are primarily a function of the amount of material flared. The open-flame nature of a flare results in inherently good Greenhouse Gases (GHG) performance (the oxidation of any methane) and prohibits the use of design features.

The source is proposing the use of elevated flares. These are the most commonly used type of flares for emergency release control. Elevated flares are capable of extremely effective control of vented gases. A potential alternative flare design is an enclosed or ground flare. However, enclosed flares are not typically considered for high flow rate situations Nevertheless, regardless of the type of flare used, there are no flare design or operational features were identified as applicable for Greenhouse Gases (GHG) control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Flare design and proper operation is not a technically feasible way to control GHGs from the Acid gas flare at this source.

Process flaring minimization practices (including operating procedures in the Flare Minimization Plan
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of Greenhouse Gases (GHG) will be less. Flaring minimization practices are feasible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Process flaring minimization practices is a technically feasible option for the control of GHG emissions from the Acid gas flare at this source.

Flare gas recovery
Flare gas recovery – Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the IG facility is not feasible for the following reasons.

(1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed IG facility will be an infrequent occurrence.

(2) Another significant difference is that refineries can recover flare gas into their fuel gas cleanup system which operates at less than 100 psig. In contrast, the IG facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of about 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor versus those at refineries.

(3) Another difference is that during some of the IG flaring events, the flared material may not be suitable to allow it to be routed to the AGR system or the AGR system itself may be in the process of being started up, in an upset, or otherwise not ready to receive the flared gases.

(4) Given the extremely infrequent nature of flared gases being available for recovery, and given the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged to be not feasible for the IG facility.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Flare gas recovery is not a technically feasible option for the control of GHG emissions from the Acid gas flare at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technology for flares is:

(1) Process flaring minimization practices (Flare Minimization Plan)

Process flaring minimization practices (Flare Minimization Plan)
Because the Acid Gas Flare is expected to be used in upset, malfunction and emergency conditions only, measures that might apply to flaring during normal start up and shutdown do not apply. Instead, the Flare Minimization Plan to reduce emissions will logically address the conduct of a root cause analysis and the consideration of corrective actions whenever flaring occurs. Therefore, the measure would be for the permittee to investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures would be implemented and documented.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC – Rockport, IN

Process flaring minimization practices (Flare Minimization Plan)

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for Greenhouse Gases (GHG) for Syngas Hydrocarbon Flare (EU-001) and Acid Gas Flare (EU-002).

A. The permittee shall comply with the following Flare Minimization Plan to reduce emissions during flaring events.

The permittee shall investigate the “root cause” of malfunction events that cause gases to be sent to a flare and determine whether there are additional preventative measures that can be implemented to minimize re-occurrence of these events. Such identified measures shall be implemented and documented.

Greenhouse Gases (GHG) BACT – Gasifier Preheater Burners (EU-008A-E)

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions. GHG control possibilities identified and addressed in this BACT analysis for these small burners are:

(1) The use of natural gas fuel, a low-carbon fuel source.
(2) Good engineering design and good combustion practices
(3) Post-combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Natural Gas Use
These burners are proposed to use only natural gas or the comparable substitute natural gas. As a low-carbon fuel source, this will minimize greenhouse gas emissions.

Good Engineering Design
These burners fire natural gas or SNG. They are relatively simple devices that are placed in the gasifier to heat it up or keep it hot when in standby. When the gasifier is about to be placed in service the burner is removed from the gasifier. An efficient design of the burner will minimize GHG impacts in two ways. First, the methane in the fuel will be efficiently burned and very little methane will remain in the combustion gases that are vented to the atmosphere. Second, efficient design is needed to achieve high temperatures. A low temperature will mean more gas is needed to preheat the gasifier.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good engineering design is a technically feasible option for the Gasifier preheater burners at this source.

Carbon Capture
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The small IG combustion sources such as the preheat burners do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of carbon capture and storage (CCS). The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the five IG Project gasifier preheat burners have a combined average annual utilization of less than 18 MMBtu/hr. As such they are an order of magnitude smaller than EPA's boiler example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the IG gasifier preheat burners is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the gasifier preheat burners are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the Gasifier preheater burners at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are 1) the use of good burner design and 2) use of only natural gas or SNG. Both are proposed so no ranking is required.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for GHG from the proposed Gasifier preheater burners:

(1) The use of good burner design; and

(2) The use of only natural gas or SNG.

The Gasifier Preheat Burners are used during the start-up of a gasifier unit. The preheat burners are portable 35 MMBtu/hr gas fired removable lance-type burners. One is utilized for each gasifier, for a total of five burners. The preheat burners combust natural gas (NG) or substitute natural gas (SNG) to generate heat to cure the refractory and to warm up a gasifier that has been down for maintenance. They are expected to operate only a small portion of the year. Once the startup preheat sequence is complete, these burners are removed from the gasifier. In addition, one burner is estimated to operate throughout the year at 18 MMBtu/hr (for approximately 5840 hr/yr) to maintain operability status of an extra gasifier when on stand-by. The reason the spare gasifier is preheated when in standby mode is to significantly shorten the time it would take to get the spare gasifier into normal operation producing syngas from coal/coke feedstock. Having to bring a spare gasifier into operation from a cold standby mode would add 24-48 hours to the time needed to achieve normal operation.

Emission Unit	**GHG Emissions (tons/yr)**			
	CO_2	**CH_4**	**N_2O**	**CO_2e**
Gasifier Preheat Burners (total for 5, EU-008A-E)	6,438	0.12	0.01	6,444

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Gasifier Preheater Burners.

1. The use of good engineering design; and

2. The use of natural gas or SNG.

3. The total CO_2 emissions from all five Gasifier Preheater Burners shall not exceed 6,438 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of the month.

Greenhouse Gases (GHG) BACT – Emergency Generators and Firewater Pumps

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from diesel engines. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

Diesel fuel is used instead of SNG or NG because it is an independent source of fuel not related to the operation of the facility. As such, it is the most reliable fuel source and its use in this application is fundamental to meeting power and water requirements in an emergency. For this reason, it is the most common fuel used for these type of emergency backup applications.

GHG control possibilities identified and addressed in this BACT analysis for these small engines are:

(1) Good engineering design
(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Good Engineering Design and Efficient Operation

The source will install engines meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. These Diesel engines are built with automatic control of the air to fuel ratio that ensures that they operate when needed and meet the applicable standards.

Carbon Capture

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The small IG combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.
The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, these IG Project miscellaneous combustion sources are an order of magnitude smaller than EPA's boiler example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the IG gasifier emergency diesel engines is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the Emergency generators and firewater pumps at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the emergency diesel generators and firewater pump diesel engines is to utilize efficient engines with good engineering design.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC

The following has been proposed as BACT for GHG emissions from the proposed Emergency generators and fire pump diesel engines: the selection and use of efficient engines with good engineering design.

This project includes two diesel-fired 1341 hp standby emergency generators (EU-009A/B) and three diesel-fired 575 hp standby fire water pumps (EU-010A-C). These engines are required for safety reasons. Each engine is expected to operate less than 52 hours per year each. That use is associated with assuring their readiness in an emergency. These emergency diesel engines will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because they will combust a hydrocarbon fuel. However, because their normal use is limited to routine maintenance, inspection and testing, their total emissions are very small (less than 100 tons CO_2e/yr). Their annual emissions in non-emergency use are as follows

Emission Units	GHG Emissions (tons/yr)			
	CO_2	**CH_4**	**N_2O**	**CO2e**
Emergency Diesel Engines (total for 5, EU-009A/B, EU-010A-C)	84	0	0	84

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Emergency diesel Engines.

The BACT shall be the use of good engineering design and efficient engines meeting applicable NSPS and MACT standards.

The total CO_2 emissions from all these emergency diesel engines, under non-emergency conditions, shall not exceed 84 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of the month.

Greenhouse Gases (GHG) BACT – ZLD Spray Dryer (EU-032)

Step 1: Identify Potential Control Technologies

The CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

GHG control possibilities identified and addressed in this BACT analysis for the small burner of the ZLD spray dryer are:

(1) The use of natural gas fuel, a low-carbon fuel source.
(2) Good engineering design and good combustion practices
(3) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Natural Gas Use
These burners are proposed to use only natural gas or SNG. As a low-carbon fuel source, this will minimize greenhouse gas emissions.

Good Engineering Design and Good Combustion Practices
The combustion of natural gas is inherently efficient, and good engineering design of the burner will assure efficient combustion.

Beyond the use of good engineering design and the use of clean natural gas (or SNG) as previously mentioned, no additional applicable good combustion practices have been identified.

Carbon Capture
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The small IG combustion sources such as the ZLD dryer do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, this IG Project miscellaneous combustion source only uses 5.2 MMBtu/hr. As such it is two orders of magnitude smaller than EPA's boiler example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the IG ZLD spray dryer is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the ZLD Spray dryer at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are

(1) The good engineering design and

(2) The use of only natural gas or SNG.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: Indiana Gasification, LLC
The following has been proposed as BACT for GHG from the proposed Zero Liquid Discharge (ZLD):

The only feasible, applicable and available control technologies identified are;

(1) The good engineering design; and

(2) The use of only natural gas or the comparable SNG.

The Zero Liquid Discharge (ZLD) system is used to process the gasification scrubber blowdown water on a continuous basis, to control the level of chlorides in the circulation loop to a safe level due to corrosion considerations. The ZLD unit processes this stream and returns the liquid back to the process as makeup water for the scrubber. The dissolved solids/salts in the blowdown water are concentrated and removed by centrifuges. The majority of the concentrate from the centrifuges is returned back to the gasification process for conversion, except for a small purge stream that removes impurities from the process.

This purge stream is dried in a spray dryer where natural gas/SNG is combusted to generate heat to evaporate the water. The solids are collected and sent to a landfill for disposal. This spray dryer is an integral part of the process that must operate on a continuous basis. Through the use of natural gas, GHGs from the fuel is limited. Fuel use in this small source is only 5.2 MMBtu/hour, generating only a small amount of GHGs.

Emission Units	**GHG Emissions (tons/yr)**			
	CO_2	**CH_4**	**N_2O**	**CO_2e**
ZLD Spray Dryer (EU-032)	2,884	0.05	0.01	2,887

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHGs for the ZLD Spray Dryer.

1. The GHG BACT for the Zero Liquid Discharge (ZLD) Spray Dryer shall be the use of good engineering design and the use of natural gas (or SNG).

2. The CO_2 emissions from the ZLD Spray Dryer shall not exceed 2,884 tons CO_2 per twelve (12) consecutive month period with compliance determined at the end of the month.

Greenhouse Gases (GHG) BACT – Fugitive Equipment Leaks (FUG & FUG-WSA)

Step 1: Identify Potential Control Technologies

The GHG emissions from fugitive equipments leaks can be controlled by;

(a) Leak detection and Repair (LDAR)

Step 2: Eliminate Technically Infeasible Options

The source estimates there will be a small amount of GHG emissions from equipment and pipe component leaks, such as pumps, valves, flanges and compressors. This includes both CO_2 and CH_4. These fugitive emissions are so small relative to the overall facility emissions and in an absolute sense that further control of fugitive emissions would have minimal additional benefit. Nevertheless, IDEM has considered the implementation of a Leak Detection and Repair (LDAR) program as technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(a) Leak Detection and Repair (LDAR)

Step 4: Evaluate the Most Effective Controls and Document the Results

The source plans to implement a Leak Detection and Repair (LDAR) program for the fugitive components of process piping that primarily contain Hazardous Air Pollutants (HAPs) or VOC. IDEM considered whether it is feasible and cost-effective to extend this program to include LDAR for piping components containing GHGs. IDEM has concluded that extending the VOC LDAR program to also include the IG facility natural gas and SNG piping components is feasible and reasonably cost-effective, costing approximately \$5/ton CO_2e. However, extending the LDAR program to include CO_2 streams would affect even less emissions on a CO2e basis, less than a tenth in comparison to methane, and it would not be cost effective. This is primarily because the global warming potential of CO_2 is 21 times less than methane. Consequently, on a CO_2e basis, controlling CO_2 through an LDAR program is much less effective and less cost-effective than implementing an LDAR program for methane (natural gas and SNG).

The IG facility has three categories of CO_2 containing streams:

1. The product CO_2 stream – 98% CO_2;
2. The acid gas stream from the AGR to the WSA – approx. 50% CO_2; and
3. The various syngas streams – 6-32% CO_2.

The table below shows the relative costs of controlling the above piping components with an LDAR program.

Costs of a NESHAPS LDAR Program for IG GHG Containing Streams

Process Streams	IG Number of Components	Uncontrolled Emissions tons/yr CO_2e	LDAR Controlled tons/yr CO_2e	IG Estimated LDAR Costs per year (Note 1)	LDAR Cost-Effectiveness \$/ton CO_2e	Primary Pollutant Controlled
NG/SNG piping (methane)	93	276	2.09	\$1,488	\$5	CO_2e
Acid Gas piping.(~50% CO_2)	232	3.6	0.058	\$3,712	\$1,035	CO_2
Product CO_2 Piping (exclude. compressor)	95	5.2	0.08	\$1,520	\$298	CO_2
Syngas (6-32% CO_2)	964	8.5	0.14	\$15,424	\$1,840	CO_2

Note 1. LDAR program costs assumed to be \$16/yr/component per US EPA 2001 Refinery Tier 2 BACT report (see separate summary in Appendix C). Costs do not include separate extra cost for purchase/maintenance of unique monitor that would be needed for CO2 monitoring (FID not responsive to CO2) .

As stated above, extending the planned VOC LDAR program to also include natural gas and SNG piping is a reasonably cost-effective measure on a CO_2e basis. However, the cost shown above for control of the CO_2 streams is not cost-effective. It should be noted that the above estimates for the product CO_2 piping excludes emissions from the seals of the CO_2 compressors. Compressor shaft seals can be one of the larger fugitive leak points, especially for very high pressure systems. Consequently, IG proposes to conduct monthly audio/visual inspection of the compressors. A high pressure leak of CO_2 would be both audibly detected and visible, due to condensation or ice formation from the auto-refrigeration of the leak.

Proposal: Indiana Gasification, LLC, IN
The following has been proposed as BACT for GHGs from the proposed Fugitives Equipment Leaks (FUG&FUG-WSA):

The BACT for fugitive GHG emissions is proposed to be use of a leak detection and repair (LDAR) program for the natural gas and SNG piping and weekly audio/visual inspection of the CO_2 compressors while they are in operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for GHG for Fugitives Equipment Leaks (FUG&FUG-WSA).

The BACT for fugitive GHG emissions is the use of a leak detection and repair (LDAR) program for the natural gas and SNG piping and weekly audio/visual inspection of the CO_2 compressors while they are in operation in any week in which there are at least twenty-four (24) hours of operation of the CO_2 compressor to be inspected.

Greenhouse Gases (GHG) BACT – Electric Circuit Breaker (FUG-SF6)

Step 1: Identify Potential Control Technologies

GHG control possibilities identified and addressed in this BACT analysis for these small potential sources are:

(1) The use of totally enclosed and pressurized circuit breakers with leak detection.
(2) The use of breakers without SF6 dielectric.

Step 2: Eliminate Technically Infeasible Options

Pressurized and enclosed breakers

The use of fully enclosed circuit breakers with leak detection (low pressure alarm) is state-of-the-art for circuit breakers and is proposed by IG. A low pressure alarm is installed on each breaker to alert operators of a loss of SF_6 gas. Operators will investigate the cause of any alarm and take corrective measures to stop the leak if one exists.

Alternative breakers without SF_6

There is no practical alternative to the use of SF_6 as the insulator and arc quenching substance in IG's circuit breakers. The unique performance qualities of SF_6 breakers is further supported by the most recent report released by the EPA SF_6 Partnership, which states: "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties." Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications. While some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute" for high-voltage applications. Therefore, the use of a breaker that doesn't contain SF_6 is judged as not feasible for this application.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) The use of totally enclosed and pressurized circuit breakers with leak detection.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for GHGs from the proposed Electric Circuit Breaker (FUG-SF6): the use of fully enclosed pressurized SF_6 circuit breakers with leak detection (low pressure alarm).

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for GHGs for Electrical Circuit Breaker (FUG-SF_6).

The GHGs BACT for the Electrical Circuit Breaker (FUG-SF_6) shall be the use of fully enclosed pressurized SF_6 circuit breakers with leak detection (low pressure alarm).

Greenhouse Gases (GHG) BACT – ZLD Inert Gas Vent (EU-033)

Step 1: Identify Potential Control Technologies

This very small inert gas vent stream from the wastewater system is primarily CO_2 and water vapor. The CO_2 in this vent is CO_2 that dissolved into the process water in the high pressure environment of the gasification system. It is released in the Zero Liquid Discharge wastewater treatment system as the pressure is dropped. The total flow rate of this vent stream is only10.4 acf/m and it contains only 204 tons/yr of CO_2 emissions. There are no known GHG controls applicable to this extremely small process vent stream.

Step 2: Eliminate Technically Infeasible Options

No technically feasible measures have been identified to control CO_2 emissions in this small vent.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

No technically feasible measures have been identified to control CO_2 emissions in this small vent.

Step 4: Evaluate the Most Effective Controls and Document the Results

No technically feasible measures have been identified to control CO_2 emissions in this small vent.

Step 5: Select BACT

No technically feasible measures have been identified to control GHG emissions in this small vent.

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)

Requirement for Best Available Control Technology (BACT), 326 IAC 8-1-6

The requirements of 326 IAC 8-1-6 (New Facilities, General Reduction Requirements) applies to facilities located anywhere in the state that are constructed on or after January 1, 1980, which have potential volatile organic compounds (VOC) emissions greater than 25 tons per year, and which are not otherwise regulated by other provisions of 326 IAC 8 rule, and requires the reduction of VOC emissions using Best Available Control Technology (BACT). The proposed Acid Gas Removal Units, identified as EU-007A and EU-007B has potential VOC emissions of greater than 25 tons per year and are therefore subject to the requirements of this rule.

326 IAC 8-1-6 requires a best available control technology (BACT) review to be performed on the proposed new emission units:

(1) Two (2) Acid Gas Removal (AGR) Unit vents, identified as EU-007A and EU-007B, to be permitted in 2012, with methanol, H_2S, COS, and CO emissions controlled by two (2) regenerative thermal oxidizers (RTO) identified as C-007A and C-007B, respectively, each nominally rated at 38.8 MMBtu/hr HHV fuel input, exhausting through two (2) stacks, identified as S-007A and S-007B.

Volatile Organic Compounds (VOCs) BACT - Acid Gas Removal Unit Vents (EU-007A and B)

Step 1: Identify Potential Control Technologies

The volatile organic compounds (VOC) emissions can be controlled by the following methods:

(1) Regenerative Thermal Oxidizer;

(2) Conventional Thermal Oxidizer;

(3) Flare; and

(3) Catalytic Oxidizer.

The Rectisol equipment will be designed to ensure that the CO_2 stream is of sufficient purity for sale, without additional purification equipment. Thus, contaminants in the AGR Vent stream, such as methanol (VOC), will have already been reduced through the inherent process design. The use of additional add-on controls to control the VOC in the AGR Vent is possible. Destruction technologies reduce VOC concentration by high temperature oxidation into carbon dioxide and water vapor.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable in reducing VOC emissions. The control technologies listed in the previous section are discussed and evaluated below for their technical feasibility.

Regenerative Thermal Oxidizer
Thermal oxidizers destroy air toxics and organic compounds that are discharged in industrial process exhausts. Thermal oxidizers achieve destruction through the process of high temperature thermal oxidation, converting combustible compounds to carbon dioxide and water vapor, and oxidizing toxic compounds to non-toxic compounds. Some thermal oxidizers preheat the incoming air by capturing heat from the outgoing air stream to reduce operating costs. Regenerative thermal oxidizers use ceramic heat transfer beds to recover thermal energy from the oxidation process. The heat transfer beds act as heat exchangers. The heat recovery can be as much as 90 to 95%. Process gas enters the RTO through an inlet manifold. The gas is directed into an energy recovery chamber which preheats the process gas. The process gas and contaminants are progressively heated in the ceramic bed as they move toward the combustion chamber.

Thermal oxidation of VOC is the most effective treatment for this AGR Vent stream prior to venting to the atmosphere. Thermal oxidation will also control other contaminants in this stream by converting methanol to CO_2 and water and COS to SO_2 and CO_2. To achieve thermal oxidation, air must be added and the combined stream heated to approximately 1600 degrees F.

The heating value of the stream to the RTO is very low because it contains mostly non-combustible CO_2 (98%). Consequently, each RTO will have a natural gas/SNG burner to raise the temperature in the combustion chamber of the RTO to approximately 1600 degrees F. This ensures a high oxidation efficiency of the CO (99%), CH_3OH (99%), H_2S (98%), and COS (98%). Most of this heat is recovered by heating one of the heat transfer beds which will be used subsequently to preheat the incoming gas stream (i.e.; the two beds are alternated between incoming gas and exhaust gas). This reduces the supplementary fuel firing rate and associated combustion emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer (RTO) is a technically feasible option for Acid Gas Recovery Unit Vent (EU-007A/B) at this source.

Conventional Thermal Oxidizer
A conventional thermal oxidizer would be technically feasible for this stream. The control efficiency of a conventional Thermal Oxidizer is the same as the Regenerative Thermal Oxidizer, and provides 99% oxidation efficiency for methanol and 98% oxidation efficiency for COS. However, a Conventional Thermal Oxidizer does not provide for heat recovery.

There is very little heating value inherent in the AGR Vent stream which has an approximate concentration of 98%v CO_2. Consequently, a conventional Thermal Oxidizer without heat recovery would have a very high supplemental fuel requirement (more than 10 times higher than a RTO) to reach a 1600 F gas temperature. Therefore, a conventional Thermal Oxidizer would have higher operating costs and higher combustion generated pollutant emissions (NO_x, VOC, PM_{10}).

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a conventional thermal oxidizer is a technically feasible option for Acid Gas Recovery Unit Vent (EU-007A/B) at this source.

Catalytic Oxidation
A catalytic oxidizer converts the VOC in the combustion gases to CO_2 at temperatures ranging from 500 degrees F to 700 degrees F in the presence of a catalyst. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate. Catalytic oxidation is proposed for the Cash Creek Generation gasification AGR Vent Stream at a

control level of at least 90%. It is not expected to perform better than an RTO or a conventional thermal oxidizer.

The use of an oxidation catalyst to control VOC emissions may be more feasible for this emission unit than for other units because the fuel is a low sulfur fuel with relatively low concentrations of other contaminants, such as metals. However, the trace COS and H2S could reduce catalyst life.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Acid Gas Recovery Unit Vent (EU-007A/B) at this source.

Flare

The overall flow rate of this stream is very high, but VOC concentrations are low. As such, the heating value of the stream is too low for effective destruction in a flare. Since there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control effectiveness versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for Acid Gas Recovery Unit Vent (EU-007A/B) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling VOC emissions from the Acid Gas Recovery (AGR) Unit Vents (EU-007 A/B).

(1) Regenerative thermal oxidation (98-99% VOC Reduction)

(2) Conventional thermal oxidation (98-99% VOC Reduction)

(3) Catalytic Oxidation (> 90% VOC Reduction)

The oxidation efficiency of VOC from both the Regenerative and Conventional Thermal Oxidizers is the same (98%). Overall VOC emissions generated from the AGR Vent stream are higher from the Conventional Thermal Oxidizer since it would require significantly more supplemental fuel firing (over 500 MMBtu/hr) and create additional combustion pollutant emissions. Thus, the regenerative thermal oxidizer will provide a superior VOC control performance compared to the conventional thermal oxidizer. A catalytic oxidizer is no more efficient.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Indiana Gasification, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

Facility	Permit / Date Issued	Facility Size	AGR Vent VOC Emission Rate	Control Technology
Draft Permit No. 147-30464-00060 Proposed Limit	**none**	**10,400 T dry coal/day**	**2.10 lb/hr based on 3-hr average (both units)**	**Regenerative Thermal Oxidizer**
Lake Charles Gasification – Louisiana	PSD-LA-742(M1) 12/30/2009	9,413 T coke/day	1.89 lb/hr 7.51 tons/yr (permitted rate, no VOC BACT)	Regenerative Thermal Oxidizer
Cash Creek Gasification – Kentucky	V-09-006 5/5/2010	770 MW	No VOC limits listed in permit except facility-wide limit of 36 tons/yr VOC.	Catalytic Oxidizer
Power Holdings of Illinois Gasification	081801AAF 10/26/2009	13,700 T coal/day	0.81 tons/yr VOM 7.2 tons/yr methanol	Oxidizers or other combustion units
Hyperion Gasification – South Dakota	28.0701-PSD 8/20/2009	>7,400 T/day	No VOC BACT or limits on this source	No controls

Note: None of these facilities has been built or operated.
Compliance determination is unknown for all these sources.

None of these projects incorporate a more effective technology or represent a more stringent emissions limit for VOCs. All but one of these other facilities has proposed use of similar thermal or catalytic oxidation for control of organics from the AGR vent. The one exception is the Hyperion project in South Dakota which has proposed no controls. For those projects with controls, the numeric limits proposed are similar to that proposed by Indiana Gasification. Slight differences in ton/yr limits likely result from process design differences in each project's AGR or gasification processes resulting in slightly different VOC amounts in the uncontrolled AGR vent stream.

Proposal: **Indiana Gasification, LLC – Rockport, IN**

The following has been proposed as BACT for VOC from the proposed Acid Gas Recovery (AGR) Unit Vents (EU-007A/B):

The BACT for this Acid Gas Recovery (AGR) Unit Vents (EU-007 A/B) is proposed to be a regenerative Thermal oxidizer with a control efficiency of 98% and limiting emissions of VOC to 1.05 pounds per hour based on a 3 hour average for each of the two AGR trains.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC for Acid Gas Recovery Unit vents (EU-007A/B).

The VOC emissions from the Acid Gas Recovery Unit vents (EU-007A/B) shall be controlled through the use of a Regenerative Thermal Oxidizer on each vent and the VOC emissions for each vent shall not exceed 1.05 pounds per hour based on a 3-hour average.

Air Quality Analysis

Indiana Gasification, LLC

Rockport, Indiana (Spencer County)

Tracking and Plant ID: 147-30464-00060

Proposed Project

Indiana Gasification, LLC (IG) first submitted their PSD modeling in April 2011. Revised modeling for NO_2, SO_2, and CO was sent in June 2011 to address modeling changes and new meteorological data. This was followed by PM_{10} and $PM_{2.5}$ modeling sent in October 2011. The October PM_{10} and $PM_{2.5}$ modeling was updated in November 2011 to address emission changes in the material handling sources.

IG proposes to construct and operate a substitute natural gas (SNG) and liquefied carbon dioxide (CO_2) production plant near the Ohio River in Spencer County, in Rockport, Indiana. The project will produce up to 48 billion standard cubic feet of SNG annually utilizing approximately 3.5 million tons of feedstock.

URS was the consultant that prepared the modeling portion of the permit application for IG. This technical support document provides the air quality analysis review of the submitted modeling by URS for IG.

Analysis Summary

Based on the potential emissions after controls, a PSD air quality analysis was triggered for SO_2, PM_{10}, $PM_{2.5}$, CO, NO_2, and sulfuric acid mist. The significant impact analysis for CO, NO_2, SO_2, and PM_{10} determined that modeling concentrations did not exceed the significant impact levels. A refined analysis was required for the 24 hour and annual $PM_{2.5}$ standards. The refined modeling showed NAAQS violations but IG was below significance whenever the violations occurred. IG was also below the 24 hour and annual $PM_{2.5}$ increment. Pre-construction monitoring requirements were not necessary since existing monitoring is available and IG was below the monitoring significance levels. 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

PM_{10}, $PM_{2.5,}$ NO_2, SO_2, CO, and sulfuric acid mist are the main pollutants that will be emitted from IG and are summarized below in Table 1. PM_{10}, $PM_{2.5,}$ NO_2, SO_2, CO, and sulfuric acid mist potential emissions after controls exceed the PSD significant emission rates and require an air quality analysis, except for sulfuric acid mist.

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	**SOURCE EMISSION RATE** (Facility totals in tons/year)	**SIGNIFICANT EMISSION RATE** (tons/year)	**PRELIMINARY AQ ANALYSIS REQUIRED**
VOC[1]	15.9	40	No[1]
PM_{10}	67.1	15	Yes
$PM_{2.5}$	60.5	10	Yes
NO_2	127	40	Yes
SO_2	<100[2]	40	Yes
CO	634	100	Yes
Sulfuric Acid Mist[3]	42.7	7	No[3]

[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. AERMOD is not a photochemical model.

[2] A source wide limit for the plant will keep it below 100 tpy. All maximum operating SO_2 emission rates cannot happen at one time.

[3] 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.

IG's emission rates were taken from Table 3-2 of their application and applicable supplemental submittals.

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) is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which affects the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where:
Hg is the GEP stack height
H is the structure height
L is the structure's lesser dimension (height or width)

New Stacks

Since some of the new stack heights for IG are below GEP stack height, the effect of aerodynamic downwash is accounted for in the air quality analysis for the project.

Meteorological Data

The National Weather Service (NWS) 1-minute Automated Surface Observation Station (ASOS) meteorological data used in AERMOD consisted of 2006 through 2010 surface data from Evansville, Indiana and upper air measurements taken at Lincoln, Illinois. The meteorological data was preprocessed using the latest versions of AERMINUTE, AERSURFACE, and AERMET.

Model Description

URS used AERMOD Version 11103. The Office of Air Quality (OAQ) used the same model version in their air quality analysis review 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 URS. The receptor grid is outlined below:

- 100 meter spacing along the facility's property boundary,
- 100 meter spacing from the property boundary to 1500 meters,
- 1000 meters spacing from 1500 meters to 10000 meters.

If a maximum predicted concentration for a particular pollutant and averaging time was located within a portion of the receptor grid spacing greater than 100 meters, a supplemental 100 meter hot spot grid was utilized.

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.

Section C - Significant Impact Level/Area (SIA) and Background Air Quality Levels

A significant impact analysis was conducted to determine if the source would exceed the PSD significant impact levels (concentrations). If the source's concentrations exceed these levels, further air quality analysis is required. Refined modeling for PM_{10}, SO_2, NO_2, and CO was not required because the results did not exceed significant impact levels. The 24-hour and annual $PM_{2.5}$ values exceeded their significant impact levels and require refined modeling. URS modeled a variety of operating scenarios to predict maximum concentrations. A complete discussion of the different operating scenarios can be found in their application and in the November 2011 particulate modeling supplemental submittal. 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. A Tier II 80% conversion of NO to NO_2 was assumed based on the March 01, 2011, Tyler Fox memorandum.

TABLE 2
Significant Impact Analysis[3]

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (μg/m^3)	SIGNIFICANT IMPACT LEVEL (μg/m^3)	REFINED AQ ANALYSIS REQUIRED
NO_2	Annual[1]	.64	1	No
NO_2	1 hour[2]	7.4	7.55	No
PM_{10}	Annual[1]	.986	1	No
PM_{10}	24 hour[1]	4.25	5	No
$PM_{2.5}$	Annual[2]	.30	.3	Yes
$PM_{2.5}$	24 hour[2]	1.66	1.2	Yes
SO_2	3 hour[1]	22.8	25	No
SO_2	24 hour[1]	2.5	5	No
SO_2	Annual[1]	.21	1	No
SO_2	1 hour[2]	7.04	7.80	No
CO	1 hour[1]	454	2000	No
CO	8 hour[1]	207	500	No

[1] The first highest values per the EPA NSR manual dated October 1990.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years modeled for comparison with the 1 hour NO_2, 1 hour SO_2, 24 hour $PM_{2.5}$ and the annual $PM_{2.5}$ SIL. See the March 01, 2011, and the March 23, 2010, memorandums
[3] Impacts are from IG 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

The modeling results were compared to the PSD preconstruction monitoring thresholds. The results are shown in the table below.

TABLE 3
Preconstruction Monitoring Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (µg/m^3)	DEMINIMIS LEVEL (µg/m3)	ABOVE DE MINIMIS LEVEL
NO_2	Annual[1]	.64	14	No
PM_{10}	24 hour[1]	4.25	10	No
$PM_{2.5}$	24 hour[2]	1.66	4	No
SO_2	24 hour[1]	2.5	13	No

[1] The first highest values per the EPA NSR manual dated October 1990. Maximum modeled impacts are from IG only.

[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 01, 2011, and the March 23, 2010, memorandums from EPA.

PM_{10}, $PM_{2.5}$, NO_2 and SO_2 did not trigger the preconstruction monitoring threshold level. IG can satisfy the preconstruction monitoring requirement since there is air quality monitoring data representative of the area in other 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 chosen for this area.

Background Monitors

Background data was taken from representative monitoring stations for IG. The background design value was used for $PM_{2.5}$. It was agreed between IG and OAQ that this approach is taken in place of the preconstruction monitoring requirement.

TABLE 4
Existing Monitoring Data Used For Background Concentrations *

Pollutant	Location	Monitoring Site	Annual Concentration (µg/m3)	24 hr Concentration (µg/m3)
$PM_{2.5}$	Owensboro, Kentucky	210590005	12.2	26

*$PM_{2.5}$ used the design value.

Section D - NAAQS and PSD Increment

OAQ supplied emission inventories of all point sources in Indiana within a 50-kilometer radius of IG. The NAAQS inventories are generated from EMITS (Emission Inventory Tracking 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 OAQ. Kentucky supplied emission inventories for their state. All sources with the potential to cause a significant concentration gradient in the vicinity of the proposed facility were explicitly included in the modeling.

NAAQS Compliance Analysis and Results for $PM_{2.5}$ 24 hour

NAAQS modeling for the 24-hour time-averaging period for $PM_{2.5}$was conducted and compared to the respective NAAQS limit. For the 24-hour modeling, two scenarios were examined and had to do with feedstock deliveries both by truck or train. These operations cannot occur at the same time due to equipment and logistical constraints. OAQ modeling results are shown in Table 5a. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years plus background were not below the NAAQS limit and a culpability analysis was required and is shown in Table 5b and Table 5c.

TABLE 5a[1]
24-Hour NAAQS Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration µg/m3	Background Concentration ug/m3	Total µg/m3	NAAQS Limit µg/m3	NAAQS Violation
$PM_{2.5}$ (Truck Scenario)	2006-2010	24 hour	17.83[2]	26	**43.83**	35	Yes
$PM_{2.5}$ (Train Scenario)	2006-2010	24 hour	17.82[2]	26	**43.82**	35	Yes

[1] 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 and different averaging techniques to obtain maximum concentrations. Tables 3 and 6 maximum concentrations are from IG only.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 23, 2010, memorandum from EPA.

Table 5b[1]
24-Hour Culpability Analysis For Truck Delivery

Highest Predicted 24-hour $PM_{2.5}$ Concentration from Cumulative Analysis for the Truck Delivery Scenario ($\mu g/m^3$)						
Maximum Modeled Concentration IG Truck Scenario + Inventory Sources	Background Design Value Owensboro Ky.	Concentration (modeled + background)	Contribution from Modeled Nearby Sources to Total	Contribution from Modeled IG Truck Scenario to Total	Is the Total Concentration ≥ NAAQS of 35µg/m3?	Is the IG contribution ≥ SIL of 1.2µg/m3?
17.83	26	**43.83**	17.68	**0.15**	yes	**no**

[1] This follows the recent U.S. EPA guidance in the March 23, 2010, memorandum on page 8 which explains how to determine significant contributions to modeled violations.

Table 5c[1]
24-Hour Culpability Analysis For Train Delivery

Highest Predicted 24-hour $PM_{2.5}$ Concentration from Cumulative Analysis for the Train Delivery Scenario ($\mu g/m^3$)						
Maximum Modeled Concentration IG train scenario + Nearby Sources	Background Design Value Owensboro Ky.	Total Tier I Concentration (modeled + background)	Contribution from Modeled Nearby Sources to Total	Contribution from Modeled IG train scenario to Total	Is the Total Concentration ≥ NAAQS of 35µg/m3?	Is the IG contribution ≥ SIL of 1.2µg/m3?
17.82	26	**43.82**	17.68	**0.14**	yes	**no**

[1] This follows the recent U.S. EPA guidance in the March 23, 2010, memorandum on page 8 which explains how to determine significant contributions to modeled violations.

Even though the model predicts a NAAQS violation, IG was not significant at the same receptor and time period. Therefore, IG does not cause or contribute to a violation of the NAAQS.

Every receptor over the standard was evaluated below the maximum modeled concentration for each scenario until there was no longer a NAAQS violation and showed IG was below significance and did not cause or contribute to a violation of the NAAQS. A table of these values can be found in the Appendix.

NAAQS Compliance Analysis and Results for $PM_{2.5}$ Annual

NAAQS modeling for the annual time period for $PM_{2.5}$ was conducted and compared to the respective NAAQS limit. OAQ modeling results are shown in Table 5d. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years plus background were below the NAAQS limit. A culpability analysis was also performed and is shown in Table 5e.

TABLE 5d[1]
Annual NAAQS Analysis

Pollutant	**Year**	**Time-Averaging**	**Maximum**	**Background**	**Total**	**NAAQS Limit**	**NAAQS**

		Period	**Concentration µg/m3**	**Concentration µg/m3**	**µg/m3**	**µg/m3**	**Violation**
$PM_{2.5}$	2006-2010	Annual	2.66[2]	12.2	**14.86**	15	No

[1] 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, and different averaging techniques to obtain maximum concentrations. Tables 3 and 6 maximum concentrations are from IG only.

[2] In accordance with recent U.S. EPA guidance, the annual concentrations may be averaged over the five years. See the March 23, 2010, memorandum from EPA.

Table 5e
Annual Culpability Analysis

Highest Predicted Annual $PM_{2.5}$ Concentration from Cumulative Analysis (µg/m^3)						
Maximum Modeled Concentration IG + Inventory Sources	Background Design Value Owensboro Ky.	Concentration (modeled + background)	Contribution from Modeled Nearby Sources to Total	Contribution from Modeled IG to Total	Is the Total Concentration ≥ NAAQS of 35µg/m3?	Is the IG contribution ≥ SIL of .3 µg/m3?
2.66	12.2	**14.86**	2.36	**0.3**	no	**yes**

Even though the maximum 5-year annual average concentration for IG was greater than or equal to the significant impact level at a few receptors, the NAAQS was not violated at the same receptors or time period. Therefore, IG does not cause or contribute to a violation of the NAAQS.

URS also performed a further analysis to evaluate how much of the background value used in this analysis may already account for emissions from modeled nearby sources. That analysis is presented in the applicant’s November 2011 particulate modeling supplemental report. The analysis showed that the nearby sources’ modeled emissions are estimated to have an annual impact at the location of the background monitor of over 4 µg/m^3. This illustrates the potential double counting of the nearby source impacts and the conservatism of the analysis.

Analysis and Results of Source Impact on the PSD Increment

Applicability

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for $PM_{2.5}$. 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 IG impacts for 24-hour and annual $PM_{2.5}$ modeled greater than or equal to significant impact levels, a PSD increment analysis for IG was required for both averaging times. Because $PM_{2.5}$ increment values were established in 2010 and the PM_{10} surrogacy policy was removed, the baseline date for the increment would be within the last few years. No sources surrounding IG are presumed to have been built in that time frame, therefore IG was the only facility modeled for comparison to the increments.

Results of the increment modeling are summarized in Table 6 below.

TABLE 6[1]
Increment Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration μg/m3	PSD Increment μg/m3	Percent Impact on the PSD Increment	Increment Violation
$PM_{2.5}$(Train Scenario)	2006-2010	24-hour[2]	1.64	9	18%	No
$PM_{2.5}$(Truck Scenario)	2006-2010	24-hour[2]	1.67	9	19%	No
$PM_{2.5}$ (Truck Scenario)	2006-2010	Annual[3]	0.33	4	8%	No

[1] 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, and different averaging techniques to obtain maximum concentrations. Tables 3 and 6 maximum concentrations are from IG only.

[2] In accordance with the Federal Register dated October 20, 2010; the high 2nd high is used.

[3] In accordance with the Federal Register dated October 20, 2010; the highest annual average is used from any of the years modeled.

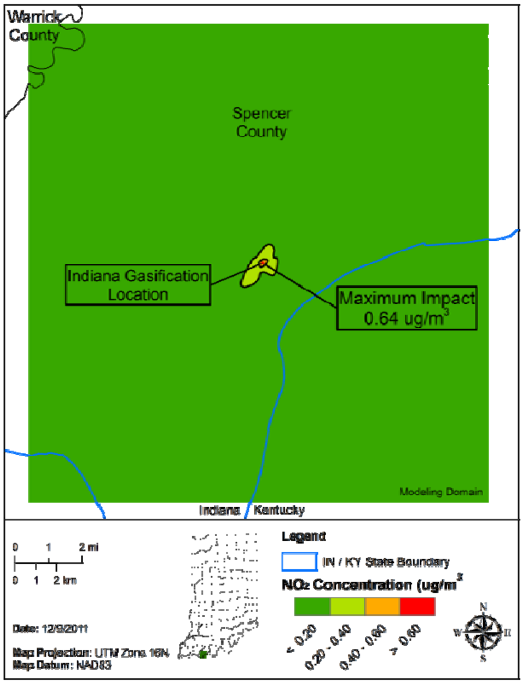
The results of the increment analysis show all pollutants for all averaging periods were below 80% of the available increment. No further analysis is required.

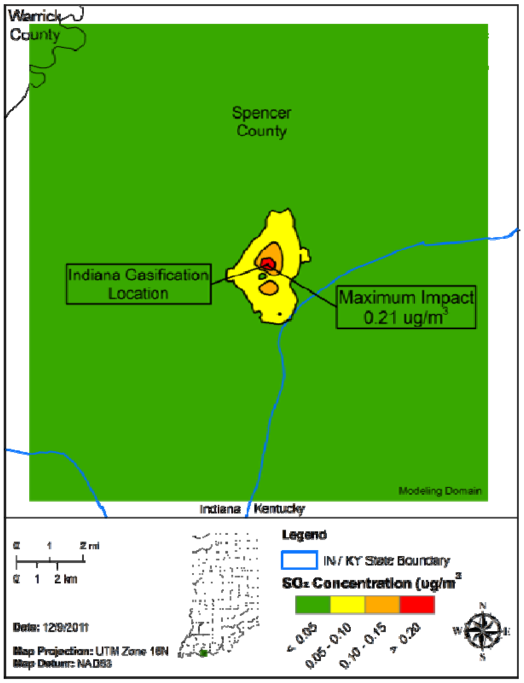
Analysis and Results of $PM_{2.5}$ secondary formation

In addition to direct emissions of $PM_{2.5}$, other pollutants, chiefly NO_x and SO_2, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Potentials to emit after controls for IG are 127 tpy NO_x and < 100 tpy SO_2.

The modeling for these two primary pollutants shows that receptor concentrations are below Significant Impact Levels (SIL) for their respective NAAQS and further diminish within the modeling domain out to 10 km to ensure the maximum concentrations are modeled.

NO_x SO_2



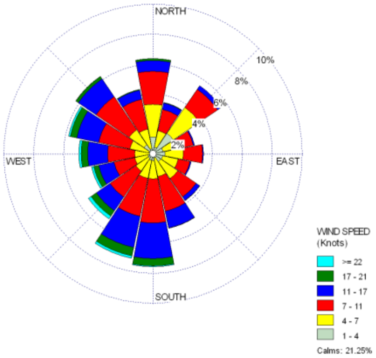


Since the NO_2 and SO_2 standards are extremely restrictive, being below the SILs would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards.

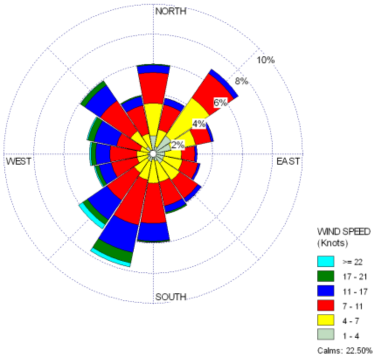
However, it is possible that some transformation into nitrates and sulfates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the impacts of an individual source of SO_2 or NO_x. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source.

The wind rose shows the general directions that emissions from this source would impact.

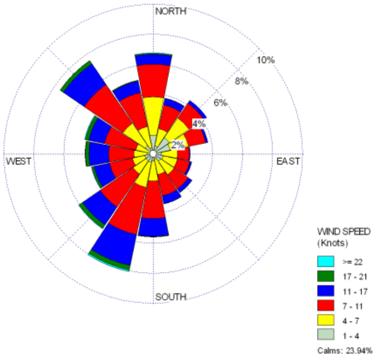
Evansville 2008



Evansville 2009



Evansville 2010



Design values from 2008 – 2010 at all Kentucky $PM_{2.5}$ monitors in the area and Indiana $PM_{2.5}$ monitors meet the annual and 24-hour NAAQS.

Because of the well established relationship between NO_x and SO_2, regional transport, and the formation of $PM_{2.5}$, to assist states to meet the $PM_{2.5}$ NAAQS, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR). This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs).

U.S. EPA used a regional model, CAMx, and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern U.S. and emission reduction levels necessary to achieve those results.

To examine the possible impact of IG, modeling U.S. EPA used to establish the final 2014 budgets in CSAPR is used for this analysis. The CSAPR website is located at http://www.epa.gov/airtransport/.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control strategy $PM_{2.5}$ concentrations are located in CSAPR_AQModeling.pdf, Appendix B, pages B-41 and B-42 for annual design values and pages B-70 to B-72 for 24-hour design values.

Information regarding SO_2 emission reductions necessary to achieve the future year modeled design values can be found in the “Significant Contribution Assessment TSD”, Table 1, page 9. This table shows the base case annual SO_2 emissions for Indiana by 2014 were projected to be 727,786 tons, and remedy control scenario annual SO_2 emissions by 2014 to be 195,046 tons. The difference between these is 532,740 tons. All surrounding states make similar significant reductions.

EPA’s Cross-State Air Pollution Rule Emission Summary for Indiana

	Pollutant	2014 Base (tons)	2014 Remedy (tons)	EGU Reduction (tons)
Indiana	SO2	727,786	195,046	532,740
Indiana	NOx	117,832	110,740	7,092

As an example, the maximum annual modeled concentrations for Spencer County are 12.66 $\mu g/m^3$ for the 2014 base case and 9.95 $\mu g/m^3$ for the 2014 control scenario. This is a reduction of 2.71 $\mu g/m^3$. In order for this modeled annual concentration reduction to occur, Indiana EGUs modeled annual SO_2 emissions by 2014 were reduced by 532,740 tons and annual NO_x emissions by 2014 were reduced by 7,092 for a total of 539,833 tons of SO_2 and NO_x. This particular monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, hundreds of thousands of tons of annual SO_2 emission reductions have also occurred by 2014, many of which would impact this site. Therefore, to estimate the impact of IG on modeled concentrations, the ratio of IG SO_2 and NO_x emissions / 539,833 tons of SO_2 and NO_x can be compared to the ratio of IG $PM_{2.5}$ impact / 2.71 $\mu g/m^3$ of $PM_{2.5}$.

The calculation to estimate secondary formation is as follows:

227 tons SO_2 & NO_x/539,833 tons SO_2 & NO_x = (IG $PM_{2.5}$ impact) .00042* 2.71 $\mu g/m^3$ of $PM_{2.5}$ = $\underline{0.00114\ \mu g/m^3 \text{ of } PM_{2.5}}$

EPA’s Cross-State Air Pollution Rule Modeling Results & Estimated IG Impact

					Anticipated	Anticipated

Monitor ID	County	2014 Base	2014 Remedy	2014 Base-Remedy (μg/m3)	Source Impact (μg/m3)	Source Impact (%)
181470009	Spencer	12.66	9.95	2.71	0.00114	0.114%

Since this concentration is well below measurable values, there would be no change in projected modeled $PM_{2.5}$ concentrations at this site.

EPA's Cross-State Air Pollution Rule Annual $PM_{2.5}$ Modeling Results & Estimated IG Impact

Monitor ID	County	2014 Base	2014 Remedy	2014 Base-Remedy (μg/m3)	Anticipated Source Impact (μg/m3)	Anticipated Source Impact (%)
180372001	Dubois	**13.72**	**11.04**	**2.68**	**0.00113**	**0.113%**
181630006	Vanderburgh	**13.19**	**11.13**	**2.06**	**0.00087**	**0.087%**
181630012	Vanderburgh	**13.25**	**11.23**	**2.02**	**0.00085**	**0.085%**
181630016	Vanderburgh	**13.43**	**11.36**	**2.07**	**0.00087**	**0.087%**

Part E – Qualitative Analysis

Additional Impact Analysis

All PSD permit applicants must prepare an additional impact 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 IG modeling submittal provided an additional impact analysis performed by URS.

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.

It is estimated that approximately 200 additional jobs will be created as a result of the proposed project. Most of the employees will be drawn from surrounding areas. 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: Moderately thick loess over weathered loamy glacial till, discontinuous loess over weathered sandstone and shale, and discontinuous loess over weathered limestone and shale.

Due to the agricultural nature of the land, crops in the Spencer County area consist mainly of corn, sorghum, wheat, soybeans, and oats (2002 Agricultural Census for Spencer County). The maximum modeled concentrations for IG are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishop's cap, horsetail, and milkweed (Flora of Indiana – Charles Deam). Livestock in Spencer County consist mainly of hogs, cattle, and sheep (2002 Agricultural Census for Spencer 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 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, 6 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 1 reptile, 3 mollusks, 1 fish, 4 birds, and 2 mammals have habitat within Spencer 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 plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. At this time 8 state endangered plant species are found in Spencer 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 Federal Class I areas include national parks and national wilderness areas and are considered environments for which minimal air quality degradation is allowed.

The nearest Class 1 area to IG is Mammoth Cave National Park which is approximately 100 km from the plant. Pursuant to a new federal guidance document (Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase 1 Report – Revised November 2010), the IG facility would not be required to conduct a Class 1 area analysis since the combined emissions of visibility impairing pollutants are less the screening threshold. The threshold is calculated by dividing the emissions by distance for sources more than 50 km from a Class 1 area. If the number is less than 10 then a visibility analysis is not required. IG did a visibility analysis anyway to show that the proposed project would not degrade visibility at Mammoth Cave National Park.

The primary visibility impairment pollutants are PM_{10}, SO_2, and NO_x. Proposed potential emissions of these pollutants from IG were examined for source contribution to visibility impairment.

The CALPUFF model was used to estimate visibility impairment from the source. CALPUFF was run for 3 annual simulations, covering calendar years 2002 to 2004. The receptors used to determine visibility impacts were taken from the National Park Service's Class I receptor index (NPS, 2005). CALPUFF requires the input of ozone and ammonia concentrations as a monthly background value applicable for the entire modeling domain. Annual background concentrations for the eastern United States are given in the Guidance for Estimating Natural Visibility Conditions (EPA 2003).

The visibility degradation beyond natural conditions is expressed in atmospheric light extinction (beta extinction = B_{ext}) and also in deciviews. A 5% change in light extinction (B_{ext}) equates to approximately 0.5 deciviews. The criteria used to determine if a source is contributing to visibility impairment is the 98th percentile that is equal to 0.5 deciviews using a maximum 24-hr emission rate.

The modeling results show that the highest change in light extinction for all years is well below 0.5 deciview threshold. Therefore, IG will not contribute to visibility impairment at Mammoth Cave National Park.

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.

The single HAP with the highest emissions is methanol, with estimated annual emissions of 7.5 tons per year. Potential emissions of aggregate HAPs are estimated not to be over 10.1tons per year.

For IG, a full HAP analysis was completed comparing the maximum estimated concentrations of each pollutant with the Unit Risk Factor (URF) or the 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 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 IG, 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 IG’s Hazard Index (HI).

This HAP screening analysis uses health protective assumptions that overestimate the actual risk associated with emissions from IG. 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 IG; rather it identifies possible avenues of risk.

The results of the HAP modeling are in Table 7.

TABLE 7
Hazardous Air Pollutant Modeling Results

Compound	CAS Number	Annual Concentration (µg/m3)	Cancer URF, (µg/m3)-1	Source	Cancer Risk	Non-Cancer Chronic RfC, µg/m3	Source of IDEM RfC	Hazard Quotient
Ammonia	7664417	0.39				100.00	IRIS	0.004
Carbonyl Sulfide	463581	0.02				12.00	TRI	0.002
Hydrogen Sulfide	7783064	0.17				2.00	IRIS	0.085
Mercury compounds	0	0.00001				0.09	CAL	0.000

Methanol	67561	1.74				4000.00	CAL	0.000
				∑ Cancer Risk	**0.0000**		**Hazard Index (HI)**	**0.0911**
				IDEM Standard	**1.0000E-06**		**IDEM Standard**	**1.00+00**
				Comparison	**Below**			**Below**

* Further information on URFs and RfCs can be found at the following EPA web site: 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 additional cancer causes in ten million people. None of the HAPs evaluated are carcinogens. 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 in ten 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, and 52 weeks a year for 70 years is minimal.

Part H - Summary of Air Quality Analysis

URS prepared the modeling portion of the PSD application. Spencer County is designated as attainment for all criteria pollutants. PM_{10}, NO_2, SO_2, CO, $PM_{2.5}$, and sulfuric acid mist emission rates associated with the proposed facility exceeded the respective significant emission rates. Modeling results taken from AERMOD model showed $PM_{2.5}$ impacts were predicted to be greater than the significant impact levels for the 24-hour and annual averaging periods. IG did not trigger the preconstruction monitoring threshold level but can satisfy the preconstruction monitoring requirement since there is existing air quality monitoring data representative of the area. The NAAQS modeling for 24-hour $PM_{2.5}$showed violations of the standard, but IG was not significant during those violations. Though IG was significant for annual $PM_{2.5}$, the NAAQS modeling did not show violations of the standard. IG was below the $PM_{2.5}$ increment modeling. Secondary $PM_{2.5}$ formation will be below measureable values. The nearest Class I area is Mammoth Cave National Park in Kentucky, just under 100 kilometers away from the source, but emissions are below the Federal Land Manager guidance screening threshold. An additional impact analysis was performed and 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.

Appendix

24-Hour $PM_{2.5}$ Culpability Analysis For Truck Delivery

X	Y	AVERAGE CONC	AVE	RANK	IG TRUCK	INVENTORY	IG TRUCK+ INVENTORY	
494100	4196600	16.33782	24-HR	1ST	0.22071	16.11712	16.33782	
494200	4196400	17.2889	24-HR	1ST	0.28825	17.00065	17.2889	
494200	4196500	17.0064	24-HR	1ST	0.27175	16.73465	17.0064	
494200	4196600	16.55326	24-HR	1ST	0.2356	16.31766	16.55326	
494200	4196700	16.18085	24-HR	1ST	0.22418	15.95668	16.18085	
494200	4196800	15.76415	24-HR	1ST	0.32961	15.43454	15.76415	
494300	4196400	17.54035	24-HR	1ST	0.2972	17.24315	17.54035	
494300	4196500	17.23232	24-HR	1ST	0.31668	16.91563	17.23232	
494300	4196600	16.70711	24-HR	1ST	0.30664	16.40047	16.70711	
494300	4196700	16.33084	24-HR	1ST	0.25681	16.07404	16.33084	
494300	4196800	16.01257	24-HR	1ST	0.34462	15.66795	16.01257	
494300	4196900	16.03167	24-HR	1ST	0.40039	15.63128	16.03167	
494400	4196400	17.69597	24-HR	1ST	0.26769	17.42828	17.69597	
494400	4196500	17.42485	24-HR	1ST	0.33606	17.08879	17.42485	
494400	4196600	16.92255	24-HR	1ST	0.35381	16.56875	16.92255	
494400	4196700	16.47253	24-HR	1ST	0.27993	16.19261	16.47253	
494400	4196800	16.20112	24-HR	1ST	0.36009	15.84103	16.20112	
494400	4196900	16.11488	24-HR	1ST	0.39841	15.71647	16.11488	
494400	4197000	16.2765	24-HR	1ST	0.42783	15.84867	16.2765	
494500	4196400	17.76407	24-HR	1ST	0.20262	17.56146	17.76407	
494500	4196500	17.52322	24-HR	1ST	0.30239	17.22084	17.52322	
494500	4196600	17.09376	24-HR	1ST	0.38405	16.70971	17.09376	
494500	4196700	16.56606	24-HR	1ST	0.30366	16.26239	16.56606	
494500	4196800	16.35886	24-HR	1ST	0.38747	15.97139	16.35886	
494500	4196900	16.19497	24-HR	1ST	0.39323	15.80174	16.19497	
494500	4197000	16.31792	24-HR	1ST	0.42845	15.88947	16.31792	
494600	4196400	17.82506	24-HR	1ST	0.14993	17.67514	17.82506	Max IG Truck + Inventory
494600	4196500	17.57066	24-HR	1ST	0.22428	17.34639	17.57066	
494600	4196600	17.18705	24-HR	1ST	0.33017	16.85689	17.18705	
494600	4196700	16.66645	24-HR	1ST	0.36746	16.29899	16.66645	
494600	4196800	16.49839	24-HR	1ST	0.41868	16.07971	16.49839	
494600	4196900	16.29663	24-HR	1ST	0.38033	15.9163	16.29663	
494600	4197000	16.30522	24-HR	1ST	0.40673	15.89848	16.30522	
494600	4197100	16.4703	24-HR	1ST	0.40428	16.06602	16.4703	
494700	4196500	17.64888	24-HR	1ST	0.15631	17.49257	17.64888	
494700	4196600	17.26526	24-HR	1ST	0.23582	17.02943	17.26526	
494700	4196700	16.7373	24-HR	1ST	0.30259	16.43472	16.7373	
494700	4196800	16.60647	24-HR	1ST	0.48872	16.11775	16.60647	
494700	4196900	16.37319	24-HR	1ST	0.36325	16.00994	16.37319	
494700	4197000	16.25425	24-HR	1ST	0.39032	15.86393	16.25425	
494700	4197100	16.47006	24-HR	1ST	0.40566	16.06439	16.47006	
494800	4196700	16.80138	24-HR	1ST	0.33863	16.46276	16.80138	
494800	4196800	16.73707	24-HR	1ST	0.45876	16.27831	16.73707	
494800	4197200	16.7471	24-HR	1ST	0.37676	16.37034	16.7471	
494806	4196692.8	16.84714	24-HR	1ST	0.2153	16.63184	16.84714	
494806	4196791.2	16.79548	24-HR	1ST	0.48673	16.30875	16.79548	
494806	4197184.8	16.71355	24-HR	1ST	0.38218	16.33137	16.71355	

494968.8	4197480	17.27565	24-HR	1ST	0.44108	16.83457	17.27565	
495050.2	4197480	17.4518	24-HR	1ST	0.61875	16.83305	17.4518	
495100	4197500	17.55386	24-HR	1ST	0.69133	16.86254	17.55386	
495131.6	4197480	17.58039	24-HR	1ST	0.73667	16.84373	17.58039	
495200	4197600	17.63595	24-HR	1ST	0.66417	16.97178	17.63595	
495221.2	4197567.4	17.66499	24-HR	1ST	0.71968	16.94532	17.66499	
495221.3	4197656.9	17.61131	24-HR	1ST	0.6139	16.99742	17.61131	
495221.3	4197746.4	17.46202	24-HR	1ST	0.52282	16.9392	17.46202	
494100	4196500	16.78272	24-HR	1ST	0.29003	16.49269	16.78272	
495100	4197600	17.54473	24-HR	1ST	0.59343	16.95131	17.54473	
495200	4197500	17.67248	24-HR	1ST	0.80501	16.86747	17.67248	Max IG Truck
495200	4197700	17.51409	24-HR	1ST	0.52982	16.98427	17.51409	
495213	4197480	17.67524	24-HR	1ST	0.72179	16.95345	17.67524	
495221.2	4197478	17.68165	24-HR	1ST	0.72352	16.95814	17.68165	
494100	4196600	14.31551	24-HR	2ND	0.25411	14.0614	14.31551	
494200	4196400	14.31916	24-HR	2ND	0.20193	14.11723	14.31916	
494200	4196500	14.4389	24-HR	2ND	0.2218	14.21711	14.4389	
494200	4196600	14.46668	24-HR	2ND	0.25653	14.21015	14.46668	
494200	4196700	14.0762	24-HR	2ND	0.36783	13.70837	14.0762	
494200	4196800	13.98417	24-HR	2ND	0.34162	13.64255	13.98417	
494300	4196400	14.34622	24-HR	2ND	0.19384	14.15238	14.34622	
494300	4196500	14.50741	24-HR	2ND	0.22865	14.27875	14.50741	
494300	4196600	14.58693	24-HR	2ND	0.24103	14.3459	14.58693	
494300	4196700	14.12922	24-HR	2ND	0.29787	13.83135	14.12922	
494300	4196800	13.95006	24-HR	2ND	0.35487	13.5952	13.95006	
494300	4196900	13.38277	24-HR	2ND	0.38208	13.00069	13.38277	
494400	4196400	14.2302	24-HR	2ND	0.16938	14.06082	14.2302	
494400	4196500	14.40677	24-HR	2ND	0.23877	14.168	14.40677	
494400	4196600	14.48656	24-HR	2ND	0.25579	14.23077	14.48656	
494400	4196700	14.09709	24-HR	2ND	0.33907	13.75803	14.09709	
494400	4196800	13.80623	24-HR	2ND	0.28428	13.52195	13.80623	
494400	4196900	13.31014	24-HR	2ND	0.35276	12.95738	13.31014	
494400	4197000	12.65316	24-HR	2ND	0.40943	12.24373	12.65316	
494500	4196400	14.1193	24-HR	2ND	0.1481	13.9712	14.1193	
494500	4196500	14.30732	24-HR	2ND	0.24454	14.06278	14.30732	
494500	4196600	14.41094	24-HR	2ND	0.31372	14.09722	14.41094	
494500	4196700	14.15072	24-HR	2ND	0.51433	13.63639	14.15072	
494500	4196800	13.75197	24-HR	2ND	0.37065	13.38132	13.75197	
494500	4196900	13.20924	24-HR	2ND	0.40486	12.80439	13.20924	
494500	4197000	12.6494	24-HR	2ND	0.50093	12.14847	12.6494	
494600	4196400	14.06843	24-HR	2ND	0.13404	13.9344	14.06843	
494600	4196500	14.21584	24-HR	2ND	0.20438	14.01145	14.21584	
494600	4196600	14.31308	24-HR	2ND	0.26436	14.04872	14.31308	
494600	4196700	14.15993	24-HR	2ND	0.43515	13.72479	14.15993	
494600	4196800	13.82507	24-HR	2ND	0.41557	13.4095	13.82507	
494600	4196900	13.22822	24-HR	2ND	0.35944	12.86878	13.22822	
494600	4197000	12.73397	24-HR	2ND	0.35519	12.37879	12.73397	
494600	4197100	12.89124	24-HR	2ND	0.37936	12.51187	12.89124	
494700	4196500	14.13924	24-HR	2ND	0.18533	13.95391	14.13924	

494700	4196600	14.19846	24-HR	2ND	0.20517	13.99329	14.19846
494700	4196700	14.08638	24-HR	2ND	0.38199	13.70439	14.08638
494700	4196800	13.85841	24-HR	2ND	0.4138	13.44461	13.85841
494700	4196900	13.27187	24-HR	2ND	0.36364	12.90823	13.27187
494700	4197000	12.85438	24-HR	2ND	0.32591	12.52847	12.85438
494700	4197100	12.94516	24-HR	2ND	0.33802	12.60715	12.94516
494800	4196700	13.9976	24-HR	2ND	0.22719	13.77041	13.9976
494800	4196800	13.74875	24-HR	2ND	0.30218	13.44657	13.74875
494800	4197200	13.02753	24-HR	2ND	0.33903	12.6885	13.02753
494806	4196692.8	14.00234	24-HR	2ND	0.19806	13.80429	14.00234
494806	4196791.2	13.79075	24-HR	2ND	0.31155	13.47921	13.79075
494806	4197184.8	13.03107	24-HR	2ND	0.35031	12.68077	13.03107
494968.8	4197480	13.47443	24-HR	2ND	0.29057	13.18386	13.47443
495050.2	4197480	13.71857	24-HR	2ND	0.44475	13.27381	13.71857
495100	4197500	13.84187	24-HR	2ND	0.51763	13.32425	13.84187
495131.6	4197480	13.80785	24-HR	2ND	0.52308	13.28477	13.80785
495200	4197600	13.91961	24-HR	2ND	0.47516	13.44444	13.91961
495221.2	4197567.4	13.93646	24-HR	2ND	0.48943	13.44703	13.93646
495221.3	4197656.9	13.8942	24-HR	2ND	0.47682	13.41738	13.8942
495221.3	4197746.4	13.65376	24-HR	2ND	0.41541	13.23836	13.65376
494100	4196500	14.36332	24-HR	2ND	0.20502	14.1583	14.36332
495100	4197600	13.89354	24-HR	2ND	0.47623	13.41731	13.89354
495200	4197500	13.86455	24-HR	2ND	0.50359	13.36097	13.86455
495200	4197700	13.78167	24-HR	2ND	0.47656	13.3051	13.78167
495213	4197480	13.81793	24-HR	2ND	0.60012	13.21781	13.81793
495221.2	4197478	13.80858	24-HR	2ND	0.60043	13.20816	13.80858
494100	4196600	12.20418	24-HR	3RD	0.308	11.89618	12.20418
494200	4196400	12.09741	24-HR	3RD	0.35293	11.74448	12.09741
494200	4196500	12.2457	24-HR	3RD	0.37689	11.86881	12.2457
494200	4196600	12.35309	24-HR	3RD	0.43354	11.91955	12.35309
494200	4196700	12.70046	24-HR	3RD	0.3546	12.34587	12.70046
494200	4196800	12.60959	24-HR	3RD	0.27931	12.33029	12.60959
494300	4196400	12.04414	24-HR	3RD	0.34088	11.70326	12.04414
494300	4196500	12.23606	24-HR	3RD	0.39803	11.83802	12.23606
494300	4196600	12.43202	24-HR	3RD	0.48414	11.94787	12.43202
494300	4196700	12.86684	24-HR	3RD	0.48764	12.3792	12.86684
494300	4196800	12.59382	24-HR	3RD	0.38427	12.20955	12.59382
494300	4196900	12.58355	24-HR	3RD	0.22934	12.35421	12.58355
494400	4196400	11.93231	24-HR	3RD	0.30923	11.62308	11.93231
494400	4196500	12.13707	24-HR	3RD	0.43965	11.69741	12.13707
494400	4196600	12.47988	24-HR	3RD	0.5591	11.92078	12.47988
494400	4196700	12.96966	24-HR	3RD	0.5539	12.41577	12.96966
494400	4196800	12.65778	24-HR	3RD	0.46248	12.1953	12.65778
494400	4196900	12.55397	24-HR	3RD	0.45213	12.10185	12.55397
494400	4197000	12.47548	24-HR	3RD	0.41948	12.05601	12.47548
494500	4196400	11.84322	24-HR	3RD	0.28625	11.55697	11.84322
494500	4196500	11.97751	24-HR	3RD	0.40225	11.57526	11.97751
494500	4196600	12.36587	24-HR	3RD	0.43458	11.93129	12.36587
494500	4196700	12.95306	24-HR	3RD	0.40724	12.54582	12.95306

494500	4196800	12.70821	24-HR	3RD	0.38635	12.32186	12.70821
494500	4196900	12.60461	24-HR	3RD	0.3264	12.27821	12.60461
494500	4197000	12.50288	24-HR	3RD	0.28539	12.21748	12.50288
494600	4196400	11.81092	24-HR	3RD	0.2214	11.58952	11.81092
494600	4196500	11.85048	24-HR	3RD	0.38948	11.461	11.85048
494600	4196600	12.24279	24-HR	3RD	0.35328	11.8895	12.24279
494600	4196700	12.86145	24-HR	3RD	0.37628	12.48516	12.86145
494600	4196800	12.70722	24-HR	3RD	0.41482	12.2924	12.70722
494600	4196900	12.5946	24-HR	3RD	0.37736	12.21724	12.5946
494600	4197000	12.58916	24-HR	3RD	0.46618	12.12297	12.58916
494600	4197100	12.2716	24-HR	3RD	0.46158	11.81002	12.2716
494700	4196500	11.9865	24-HR	3RD	0.13145	11.85504	11.9865
494700	4196600	12.35013	24-HR	3RD	0.25704	12.09309	12.35013
494700	4196700	12.86745	24-HR	3RD	0.22783	12.63962	12.86745
494700	4196800	12.7499	24-HR	3RD	0.27944	12.47046	12.7499
494700	4196900	12.64118	24-HR	3RD	0.32613	12.31505	12.64118
494700	4197000	12.60937	24-HR	3RD	0.35889	12.25048	12.60937
494700	4197100	12.38265	24-HR	3RD	0.47773	11.90491	12.38265
494800	4196700	13.06513	24-HR	3RD	0.15818	12.90695	13.06513
494800	4196800	12.90494	24-HR	3RD	0.25395	12.65099	12.90494
494800	4197200	12.12955	24-HR	3RD	0.20594	11.92361	12.12955
494806	4196692.8	13.034	24-HR	3RD	0.26935	12.76465	13.034
494806	4196791.2	12.97781	24-HR	3RD	0.38293	12.59488	12.97781
494806	4197184.8	12.1591	24-HR	3RD	0.20389	11.95521	12.1591
494968.8	4197480	11.95197	24-HR	3RD	0.43121	11.52076	11.95197
495050.2	4197480	12.26537	24-HR	3RD	0.45242	11.81295	12.26537
495100	4197500	12.36822	24-HR	3RD	0.47714	11.89109	12.36822
495131.6	4197480	12.50605	24-HR	3RD	0.51638	11.98967	12.50605
495200	4197600	12.35635	24-HR	3RD	0.53489	11.82146	12.35635
495221.2	4197567.4	12.45341	24-HR	3RD	0.56911	11.8843	12.45341
495221.3	4197656.9	12.22747	24-HR	3RD	0.50961	11.71786	12.22747
495221.3	4197746.4	12.02651	24-HR	3RD	0.43945	11.58706	12.02651
494100	4196500	12.05131	24-HR	3RD	0.29291	11.7584	12.05131
495100	4197600	12.06222	24-HR	3RD	0.37994	11.68228	12.06222
495200	4197500	12.57467	24-HR	3RD	0.57671	11.99796	12.57467
495200	4197700	12.06348	24-HR	3RD	0.40459	11.6589	12.06348
495213	4197480	12.61493	24-HR	3RD	0.58739	12.02754	12.61493
495221.2	4197478	12.62201	24-HR	3RD	0.59223	12.02979	12.62201
494100	4196600	11.77262	24-HR	4TH	0.28139	11.49122	11.77262
494200	4196400	11.08252	24-HR	4TH	0.1277	10.95483	11.08252
494200	4196500	11.43195	24-HR	4TH	0.19015	11.24181	11.43195
494200	4196600	11.76516	24-HR	4TH	0.24436	11.5208	11.76516
494200	4196700	11.80757	24-HR	4TH	0.18334	11.62424	11.80757
494200	4196800	11.9681	24-HR	4TH	0.19214	11.77596	11.9681
494300	4196400	11.26167	24-HR	4TH	0.24111	11.02056	11.26167
494300	4196500	11.47287	24-HR	4TH	0.1867	11.28618	11.47287
494300	4196600	11.79559	24-HR	4TH	0.25646	11.53913	11.79559
494300	4196700	11.77902	24-HR	4TH	0.18388	11.59514	11.77902
494300	4196800	11.96871	24-HR	4TH	0.13024	11.83846	11.96871

494300	4196900	11.97394	24-HR	4TH	0.31623	11.65771	11.97394
494400	4196400	11.38455	24-HR	4TH	0.15771	11.22684	11.38455
494400	4196500	11.45313	24-HR	4TH	0.13014	11.32299	11.45313
494400	4196600	11.77043	24-HR	4TH	0.23301	11.53742	11.77043
494400	4196700	11.76351	24-HR	4TH	0.19559	11.56792	11.76351
494400	4196800	11.91192	24-HR	4TH	0.16579	11.74613	11.91192
494400	4196900	11.94932	24-HR	4TH	0.15527	11.79405	11.94932
494400	4197000	12.09748	24-HR	4TH	0.22246	11.87502	12.09748
494500	4196400	11.39801	24-HR	4TH	0.10376	11.29425	11.39801
494500	4196500	11.31113	24-HR	4TH	0.05841	11.25272	11.31113
494500	4196600	11.64559	24-HR	4TH	0.26624	11.37935	11.64559
494500	4196700	11.6493	24-HR	4TH	0.2157	11.4336	11.6493
494500	4196800	11.80521	24-HR	4TH	0.30376	11.50145	11.80521
494500	4196900	11.87297	24-HR	4TH	0.22298	11.64998	11.87297
494500	4197000	12.05947	24-HR	4TH	0.38792	11.67155	12.05947
494600	4196400	11.45132	24-HR	4TH	0.14376	11.30756	11.45132
494600	4196500	11.42298	24-HR	4TH	0.05979	11.36319	11.42298
494600	4196600	11.59289	24-HR	4TH	0.18219	11.4107	11.59289
494600	4196700	11.50347	24-HR	4TH	0.1844	11.31906	11.50347
494600	4196800	11.73607	24-HR	4TH	0.3188	11.41727	11.73607
494600	4196900	11.85941	24-HR	4TH	0.10078	11.75863	11.85941
494600	4197000	11.99254	24-HR	4TH	0.24376	11.74878	11.99254
494600	4197100	11.86579	24-HR	4TH	0.48526	11.38052	11.86579
494700	4196500	11.5332	24-HR	4TH	0.31658	11.21661	11.5332
494700	4196600	11.64623	24-HR	4TH	0.23168	11.41455	11.64623
494700	4196700	11.59425	24-HR	4TH	0.08651	11.50774	11.59425
494700	4196800	11.80148	24-HR	4TH	0.23156	11.56993	11.80148
494700	4196900	11.83701	24-HR	4TH	0.15079	11.68622	11.83701
494700	4197000	12.05373	24-HR	4TH	0.31906	11.73467	12.05373
494700	4197100	11.95247	24-HR	4TH	0.34353	11.60894	11.95247
494800	4196700	11.6856	24-HR	4TH	0.07525	11.61035	11.6856
494800	4196800	12.08367	24-HR	4TH	0.31104	11.77263	12.08367
494800	4197200	11.64281	24-HR	4TH	0.33681	11.306	11.64281
494806	4196692.8	11.6785	24-HR	4TH	0.07026	11.60824	11.6785
494806	4196791.2	12.11341	24-HR	4TH	0.24423	11.86918	12.11341
494806	4197184.8	11.73643	24-HR	4TH	0.34283	11.3936	11.73643
494968.8	4197480	11.07207	24-HR	4TH	0.23424	10.83783	11.07207
495050.2	4197480	11.17667	24-HR	4TH	0.53954	10.63713	11.17667
495100	4197500	11.246	24-HR	4TH	0.4045	10.8415	11.246
495131.6	4197480	11.36659	24-HR	4TH	0.56813	10.79846	11.36659
495200	4197600	11.43739	24-HR	4TH	0.38423	11.05317	11.43739
495221.2	4197567.4	11.48812	24-HR	4TH	0.44889	11.03923	11.48812
495221.3	4197656.9	11.38437	24-HR	4TH	0.32079	11.06358	11.38437
495221.3	4197746.4	11.27551	24-HR	4TH	0.40708	10.86843	11.27551
494100	4196500	11.43289	24-HR	4TH	0.19611	11.23678	11.43289
495100	4197600	11.28655	24-HR	4TH	0.2884	10.99815	11.28655
495200	4197500	11.5069	24-HR	4TH	0.62518	10.88172	11.5069
495200	4197700	11.30136	24-HR	4TH	0.30033	11.00103	11.30136
495213	4197480	11.54423	24-HR	4TH	0.62715	10.91708	11.54423

495221.2	4197478	11.55223	24-HR	4TH	0.6214	10.93083	11.55223
494100	4196600	11.00226	24-HR	5TH	0.0778	10.92446	11.00226
494200	4196400	10.61941	24-HR	5TH	0.20399	10.41542	10.61941
494200	4196500	10.70599	24-HR	5TH	0.13713	10.56886	10.70599
494200	4196600	11.04175	24-HR	5TH	0.08276	10.95899	11.04175
494200	4196700	11.34827	24-HR	5TH	0.166	11.18227	11.34827
494200	4196800	11.1347	24-HR	5TH	0.14832	10.98638	11.1347
494300	4196400	10.72349	24-HR	5TH	0.10757	10.61591	10.72349
494300	4196500	10.85526	24-HR	5TH	0.14119	10.71407	10.85526
494300	4196600	11.04264	24-HR	5TH	0.07998	10.96265	11.04264
494300	4196700	11.31622	24-HR	5TH	0.17946	11.13676	11.31622
494300	4196800	11.14768	24-HR	5TH	0.16528	10.9824	11.14768
494300	4196900	11.00503	24-HR	5TH	0.18203	10.823	11.00503
494400	4196400	10.76863	24-HR	5TH	0.20086	10.56777	10.76863
494400	4196500	10.99649	24-HR	5TH	0.11382	10.88267	10.99649
494400	4196600	10.99472	24-HR	5TH	0.05462	10.9401	10.99472
494400	4196700	11.30376	24-HR	5TH	0.20312	11.10064	11.30376
494400	4196800	11.10934	24-HR	5TH	0.16777	10.94157	11.10934
494400	4196900	10.99394	24-HR	5TH	0.18738	10.80656	10.99394
494400	4197000	11.09134	24-HR	5TH	0.23419	10.85716	11.09134
494500	4196400	10.68692	24-HR	5TH	0.23683	10.4501	10.68692
494500	4196500	11.10713	24-HR	5TH	0.18035	10.92678	11.10713
494500	4196600	11.10894	24-HR	5TH	0.05178	11.05716	11.10894
494500	4196700	11.26602	24-HR	5TH	0.29132	10.9747	11.26602
494500	4196800	11.11737	24-HR	5TH	0.19604	10.92134	11.11737
494500	4196900	11.00747	24-HR	5TH	0.29857	10.7089	11.00747
494500	4197000	11.03903	24-HR	5TH	0.13456	10.90447	11.03903
494600	4196400	10.68009	24-HR	5TH	0.14657	10.53352	10.68009
494600	4196500	11.06682	24-HR	5TH	0.109	10.95783	11.06682
494600	4196600	11.13745	24-HR	5TH	0.10969	11.02776	11.13745
494600	4196700	11.31948	24-HR	5TH	0.2512	11.06828	11.31948
494600	4196800	11.16299	24-HR	5TH	0.25218	10.91081	11.16299
494600	4196900	10.97449	24-HR	5TH	0.42393	10.55055	10.97449
494600	4197000	10.98154	24-HR	5TH	0.23653	10.74501	10.98154
494600	4197100	10.89352	24-HR	5TH	0.16978	10.72375	10.89352
494700	4196500	11.03022	24-HR	5TH	0.08284	10.94737	11.03022
494700	4196600	11.21783	24-HR	5TH	0.08888	11.12895	11.21783
494700	4196700	11.40912	24-HR	5TH	0.28018	11.12893	11.40912
494700	4196800	11.27083	24-HR	5TH	0.26479	11.00604	11.27083
494700	4196900	11.16957	24-HR	5TH	0.29907	10.8705	11.16957
494700	4197000	11.15088	24-HR	5TH	0.17969	10.97119	11.15088
494700	4197100	10.98248	24-HR	5TH	0.18163	10.80084	10.98248
494800	4196700	11.46297	24-HR	5TH	0.24151	11.22146	11.46297
494800	4196800	11.3087	24-HR	5TH	0.28967	11.01902	11.3087
494800	4197200	10.84332	24-HR	5TH	0.28375	10.55957	10.84332
494806	4196692.8	11.47414	24-HR	5TH	0.23682	11.23733	11.47414
494806	4196791.2	11.34511	24-HR	5TH	0.31352	11.03159	11.34511
494806	4197184.8	10.91783	24-HR	5TH	0.29082	10.62701	10.91783
494968.8	4197480	10.70951	24-HR	5TH	0.43641	10.2731	10.70951

495050.2	4197480	10.84379	24-HR	5TH	0.42402	10.41977	10.84379
495100	4197500	10.73801	24-HR	5TH	0.55118	10.18683	10.73801
495131.6	4197480	10.82144	24-HR	5TH	0.48621	10.33523	10.82144
495200	4197600	10.50026	24-HR	5TH	0.49114	10.00912	10.50026
495221.2	4197567.4	10.61319	24-HR	5TH	0.47434	10.13885	10.61319
495221.3	4197656.9	10.54261	24-HR	5TH	0.45249	10.09011	10.54261
495221.3	4197746.4	10.45707	24-HR	5TH	0.45024	10.00683	10.45707
494100	4196500	10.59021	24-HR	5TH	0.11961	10.4706	10.59021
495100	4197600	10.24728	24-HR	5TH	0.43484	9.81244	10.24728
495200	4197500	10.91201	24-HR	5TH	0.40472	10.50728	10.91201
495200	4197700	10.46275	24-HR	5TH	0.39993	10.06282	10.46275
495213	4197480	10.98889	24-HR	5TH	0.4906	10.49829	10.98889
495221.2	4197478	11.00357	24-HR	5TH	0.49073	10.51284	11.00357
494100	4196600	10.43503	24-HR	6TH	0.17194	10.26308	10.43503
494200	4196400	10.06684	24-HR	6TH	0.31327	9.75357	10.06684
494200	4196500	10.325	24-HR	6TH	0.1839	10.14111	10.325
494200	4196600	10.45199	24-HR	6TH	0.20418	10.24781	10.45199
494200	4196700	10.61364	24-HR	6TH	0.20745	10.40619	10.61364
494200	4196800	10.61749	24-HR	6TH	0.16142	10.45607	10.61749
494300	4196400	9.92545	24-HR	6TH	0.37149	9.55396	9.92545
494300	4196500	10.23881	24-HR	6TH	0.32435	9.91447	10.23881
494300	4196600	10.40825	24-HR	6TH	0.24852	10.15973	10.40825
494300	4196700	10.60858	24-HR	6TH	0.27114	10.33744	10.60858
494300	4196800	10.6382	24-HR	6TH	0.19221	10.44599	10.6382
494300	4196900	10.48275	24-HR	6TH	0.16232	10.32043	10.48275
494400	4196400	9.81696	24-HR	6TH	0.14751	9.66944	9.81696
494400	4196500	10.17807	24-HR	6TH	0.29791	9.88016	10.17807
494400	4196600	10.48171	24-HR	6TH	0.23144	10.25026	10.48171
494400	4196700	10.52178	24-HR	6TH	0.3175	10.20427	10.52178
494400	4196800	10.63506	24-HR	6TH	0.34418	10.29088	10.63506
494400	4196900	10.48673	24-HR	6TH	0.29572	10.19101	10.48673
494400	4197000	10.49082	24-HR	6TH	0.26477	10.22605	10.49082
494500	4196400	9.92146	24-HR	6TH	0.10712	9.81434	9.92146
494500	4196500	10.17766	24-HR	6TH	0.2308	9.94687	10.17766
494500	4196600	10.50669	24-HR	6TH	0.16017	10.34652	10.50669
494500	4196700	10.58648	24-HR	6TH	0.16774	10.41874	10.58648
494500	4196800	10.65598	24-HR	6TH	0.19797	10.45801	10.65598
494500	4196900	10.54822	24-HR	6TH	0.09252	10.4557	10.54822
494500	4197000	10.55933	24-HR	6TH	0.20902	10.35032	10.55933
494600	4196400	9.7835	24-HR	6TH	0.1617	9.6218	9.7835
494600	4196500	10.14394	24-HR	6TH	0.20256	9.94138	10.14394
494600	4196600	10.63389	24-HR	6TH	0.17836	10.45553	10.63389
494600	4196700	10.68026	24-HR	6TH	0.20703	10.47323	10.68026
494600	4196800	10.75745	24-HR	6TH	0.30357	10.45387	10.75745
494600	4196900	10.67112	24-HR	6TH	0.10751	10.56361	10.67112
494600	4197000	10.65727	24-HR	6TH	0.22281	10.43446	10.65727
494600	4197100	10.45308	24-HR	6TH	0.22392	10.22916	10.45308
494700	4196500	10.0032	24-HR	6TH	0.0695	9.9337	10.0032
494700	4196600	10.46156	24-HR	6TH	0.12521	10.33635	10.46156

494700	4196700	10.61766	24-HR	6TH	0.21382	10.40384	10.61766
494700	4196800	10.6995	24-HR	6TH	0.36281	10.33669	10.6995
494700	4196900	10.53244	24-HR	6TH	0.22061	10.31183	10.53244
494700	4197000	10.47529	24-HR	6TH	0.23441	10.24089	10.47529
494700	4197100	10.35373	24-HR	6TH	0.36432	9.98941	10.35373
494800	4196700	10.49609	24-HR	6TH	0.13601	10.36008	10.49609
494800	4196800	10.55259	24-HR	6TH	0.32645	10.22614	10.55259
494800	4197200	10.20984	24-HR	6TH	0.17165	10.03819	10.20984
494806	4196692.8	10.4823	24-HR	6TH	0.1175	10.36479	10.4823
494806	4196791.2	10.53585	24-HR	6TH	0.30948	10.22637	10.53585
494806	4197184.8	10.20213	24-HR	6TH	0.18084	10.02128	10.20213
494968.8	4197480	9.82878	24-HR	6TH	0.42642	9.40236	9.82878
495050.2	4197480	9.94048	24-HR	6TH	0.60826	9.33222	9.94048
495100	4197500	9.95025	24-HR	6TH	0.63496	9.31529	9.95025
495131.6	4197480	9.99759	24-HR	6TH	0.68857	9.30902	9.99759
495200	4197600	9.89595	24-HR	6TH	0.57901	9.31694	9.89595
495221.2	4197567.4	10.01585	24-HR	6TH	0.67595	9.33991	10.01585
495221.3	4197656.9	9.81034	24-HR	6TH	0.70121	9.10913	9.81034
495221.3	4197746.4	9.88026	24-HR	6TH	0.33561	9.54465	9.88026
494100	4196500	10.3738	24-HR	6TH	0.33337	10.04043	10.3738
495100	4197600	9.80357	24-HR	6TH	0.41398	9.38959	9.80357
495200	4197500	10.09163	24-HR	6TH	0.74265	9.34898	10.09163
495200	4197700	9.83211	24-HR	6TH	0.5564	9.27571	9.83211
495213	4197480	10.11688	24-HR	6TH	0.73464	9.38224	10.11688
495221.2	4197478	10.11869	24-HR	6TH	0.72559	9.3931	10.11869
494100	4196600	9.83479	24-HR	7TH	0.27835	9.55644	9.83479
494200	4196400	9.79916	24-HR	7TH	0.30962	9.48953	9.79916
494200	4196500	9.93565	24-HR	7TH	0.53839	9.39727	9.93565
494200	4196600	9.88404	24-HR	7TH	0.14481	9.73923	9.88404
494200	4196700	9.71365	24-HR	7TH	0.14203	9.57162	9.71365
494200	4196800	9.92425	24-HR	7TH	0.28507	9.63918	9.92425
494300	4196400	9.65346	24-HR	7TH	0.17264	9.48083	9.65346
494300	4196500	9.95767	24-HR	7TH	0.29985	9.65782	9.95767
494300	4196600	9.95148	24-HR	7TH	0.14852	9.80297	9.95148
494300	4196700	9.87433	24-HR	7TH	0.11538	9.75895	9.87433
494300	4196800	10.04267	24-HR	7TH	0.27245	9.77022	10.04267
494300	4196900	10.02676	24-HR	7TH	0.3493	9.67746	10.02676
494400	4196400	9.49775	24-HR	7TH	0.29337	9.20438	9.49775
494400	4196500	9.88254	24-HR	7TH	0.28202	9.60052	9.88254
494400	4196600	9.9725	24-HR	7TH	0.44727	9.52523	9.9725
494400	4196700	10.0757	24-HR	7TH	0.11445	9.96124	10.0757
494400	4196800	10.25759	24-HR	7TH	0.27242	9.98517	10.25759
494400	4196900	10.14502	24-HR	7TH	0.22054	9.92448	10.14502
494400	4197000	10.09082	24-HR	7TH	0.30443	9.78639	10.09082
494500	4196400	9.44396	24-HR	7TH	0.17683	9.26713	9.44396
494500	4196500	9.81471	24-HR	7TH	0.10196	9.71275	9.81471
494500	4196600	9.87534	24-HR	7TH	0.31412	9.56122	9.87534
494500	4196700	10.12714	24-HR	7TH	0.2566	9.87053	10.12714
494500	4196800	10.3388	24-HR	7TH	0.39301	9.94579	10.3388

494500	4196900	10.23015	24-HR	7TH	0.43665	9.7935	10.23015
494500	4197000	10.099	24-HR	7TH	0.32265	9.77635	10.099
494600	4196400	9.44932	24-HR	7TH	0.03723	9.4121	9.44932
494600	4196500	9.79008	24-HR	7TH	0.05461	9.73547	9.79008
494600	4196600	9.82503	24-HR	7TH	0.21305	9.61198	9.82503
494600	4196700	10.13098	24-HR	7TH	0.39987	9.73111	10.13098
494600	4196800	10.24888	24-HR	7TH	0.33174	9.91714	10.24888
494600	4196900	10.14365	24-HR	7TH	0.45535	9.6883	10.14365
494600	4197000	10.08972	24-HR	7TH	0.32098	9.76874	10.08972
494600	4197100	10.02869	24-HR	7TH	0.2511	9.77759	10.02869
494700	4196500	9.72484	24-HR	7TH	0.08603	9.63881	9.72484
494700	4196600	9.8169	24-HR	7TH	0.14758	9.66933	9.8169
494700	4196700	9.96981	24-HR	7TH	0.2742	9.69561	9.96981
494700	4196800	9.99381	24-HR	7TH	0.415	9.57882	9.99381
494700	4196900	10.09474	24-HR	7TH	0.40543	9.6893	10.09474
494700	4197000	10.03234	24-HR	7TH	0.27475	9.75758	10.03234
494700	4197100	9.96722	24-HR	7TH	0.24131	9.72591	9.96722
494800	4196700	9.84648	24-HR	7TH	0.19832	9.64817	9.84648
494800	4196800	9.8946	24-HR	7TH	0.23427	9.66032	9.8946
494800	4197200	9.77508	24-HR	7TH	0.41337	9.36171	9.77508
494806	4196692.8	9.79291	24-HR	7TH	0.17369	9.61922	9.79291
494806	4196791.2	9.98754	24-HR	7TH	0.30117	9.68637	9.98754
494806	4197184.8	9.76922	24-HR	7TH	0.42156	9.34766	9.76922
494968.8	4197480	9.49304	24-HR	7TH	0.39142	9.10161	9.49304
495050.2	4197480	9.60238	24-HR	7TH	0.37056	9.23181	9.60238
495100	4197500	9.65555	24-HR	7TH	0.37233	9.28322	9.65555
495131.6	4197480	9.73231	24-HR	7TH	0.44075	9.29155	9.73231
495200	4197600	9.61915	24-HR	7TH	0.43354	9.18562	9.61915
495221.2	4197567.4	9.70958	24-HR	7TH	0.39331	9.31628	9.70958
495221.3	4197656.9	9.49476	24-HR	7TH	0.21256	9.28221	9.49476
495221.3	4197746.4	9.279	24-HR	7TH	0.44856	8.83044	9.279
494100	4196500	9.85909	24-HR	7TH	0.13344	9.72565	9.85909
495100	4197600	9.49488	24-HR	7TH	0.38351	9.11137	9.49488
495200	4197500	9.79168	24-HR	7TH	0.51256	9.27912	9.79168
495200	4197700	9.29635	24-HR	7TH	0.23303	9.06332	9.29635
495213	4197480	9.79573	24-HR	7TH	0.45006	9.34567	9.79573
495221.2	4197478	9.79756	24-HR	7TH	0.45114	9.34643	9.79756
494100	4196600	9.39381	24-HR	8TH	0.1562	9.23762	9.39381
494200	4196400	9.25345	24-HR	8TH	0.2392	9.01425	9.25345
494200	4196500	9.61968	24-HR	8TH	0.17891	9.44077	9.61968
494200	4196600	9.5625	24-HR	8TH	0.40475	9.15775	9.5625
494200	4196700	9.52076	24-HR	8TH	0.40246	9.1183	9.52076
494200	4196800	9.5181	24-HR	8TH	0.35052	9.16757	9.5181
494300	4196400	9.34767	24-HR	8TH	0.26036	9.08732	9.34767
494300	4196500	9.58448	24-HR	8TH	0.26322	9.32126	9.58448
494300	4196600	9.66669	24-HR	8TH	0.40763	9.25906	9.66669
494300	4196700	9.52297	24-HR	8TH	0.16933	9.35365	9.52297
494300	4196800	9.6653	24-HR	8TH	0.38848	9.27681	9.6653
494300	4196900	9.75128	24-HR	8TH	0.27479	9.47649	9.75128

494400	4196400	9.33795	24-HR	8TH	0.26623	9.07171	9.33795
494400	4196500	9.50232	24-HR	8TH	0.20175	9.30058	9.50232
494400	4196600	9.66308	24-HR	8TH	0.16938	9.4937	9.66308
494400	4196700	9.51898	24-HR	8TH	0.31489	9.20409	9.51898
494400	4196800	9.67081	24-HR	8TH	0.35128	9.31953	9.67081
494400	4196900	9.90889	24-HR	8TH	0.35901	9.54989	9.90889
494400	4197000	9.59134	24-HR	8TH	0.4904	9.10094	9.59134
494500	4196400	9.28688	24-HR	8TH	0.11837	9.16851	9.28688
494500	4196500	9.52061	24-HR	8TH	0.20885	9.31177	9.52061
494500	4196600	9.64716	24-HR	8TH	0.39633	9.25083	9.64716
494500	4196700	9.59351	24-HR	8TH	0.50124	9.09227	9.59351
494500	4196800	9.64239	24-HR	8TH	0.53211	9.11028	9.64239
494500	4196900	9.90753	24-HR	8TH	0.34052	9.56701	9.90753
494500	4197000	9.71942	24-HR	8TH	0.63452	9.0849	9.71942
494600	4196400	9.21758	24-HR	8TH	0.1302	9.08738	9.21758
494600	4196500	9.28379	24-HR	8TH	0.23446	9.04933	9.28379
494600	4196600	9.44796	24-HR	8TH	0.38186	9.0661	9.44796
494600	4196700	9.54581	24-HR	8TH	0.36576	9.18004	9.54581
494600	4196800	9.61937	24-HR	8TH	0.55847	9.0609	9.61937
494600	4196900	9.85634	24-HR	8TH	0.32562	9.53072	9.85634
494600	4197000	9.69151	24-HR	8TH	0.51704	9.17448	9.69151
494600	4197100	9.66401	24-HR	8TH	0.6277	9.03631	9.66401
494700	4196500	9.22139	24-HR	8TH	0.12701	9.09438	9.22139
494700	4196600	9.18356	24-HR	8TH	0.25011	8.93344	9.18356
494700	4196700	9.43439	24-HR	8TH	0.28332	9.15107	9.43439
494700	4196800	9.56668	24-HR	8TH	0.22798	9.3387	9.56668
494700	4196900	9.73457	24-HR	8TH	0.33582	9.39874	9.73457
494700	4197000	9.57887	24-HR	8TH	0.53692	9.04195	9.57887
494700	4197100	9.56524	24-HR	8TH	0.53745	9.02778	9.56524
494800	4196700	9.28995	24-HR	8TH	0.26688	9.02306	9.28995
494800	4196800	9.4667	24-HR	8TH	0.26154	9.20516	9.4667
494800	4197200	9.41162	24-HR	8TH	0.34795	9.06366	9.41162
494806	4196692.8	9.27293	24-HR	8TH	0.2633	9.00963	9.27293
494806	4196791.2	9.4873	24-HR	8TH	0.39924	9.08806	9.4873
494806	4197184.8	9.41205	24-HR	8TH	0.34758	9.06447	9.41205
494968.8	4197480	9.1192	24-HR	8TH	0.21292	8.90628	9.1192
495050.2	4197480	9.17914	24-HR	8TH	0.53515	8.644	9.17914
495100	4197500	9.23284	24-HR	8TH	0.65732	8.57552	9.23284
495131.6	4197480	9.37836	24-HR	8TH	0.64061	8.73774	9.37836
495200	4197600	9.18494	24-HR	8TH	0.59846	8.58648	9.18494
495221.2	4197567.4	9.21643	24-HR	8TH	0.64881	8.56763	9.21643
495221.3	4197656.9	9.17158	24-HR	8TH	0.50069	8.67088	9.17158
495221.3	4197746.4	9.02184	24-HR	8TH	0.29306	8.72878	9.02184
494100	4196500	9.46595	24-HR	8TH	0.38602	9.07993	9.46595
495100	4197600	8.9731	24-HR	8TH	0	0	0
495200	4197500	9.35293	24-HR	8TH	0.73494	8.61799	9.35293
495200	4197700	9.04817	24-HR	8TH	0.36276	8.68541	9.04817
495213	4197480	9.46262	24-HR	8TH	0.73651	8.72611	9.46262
495221.2	4197478	9.48093	24-HR	8TH	0.68023	8.8007	9.48093

494100	4196600	9.06823	24-HR	9TH	0.28369	8.78454	9.06823
494200	4196400	9.12416	24-HR	9TH	0.10535	9.01881	9.12416
494200	4196500	9.06315	24-HR	9TH	0.14764	8.91551	9.06315
494200	4196600	9.23736	24-HR	9TH	0.2653	8.97206	9.23736
494200	4196700	9.24582	24-HR	9TH	0.28375	8.96207	9.24582
494200	4196800	9.27318	24-HR	9TH	0.17697	9.09621	9.27318
494300	4196400	9.12592	24-HR	9TH	0.10517	9.02075	9.12592
494300	4196500	9.13533	24-HR	9TH	0.10079	9.03454	9.13533
494300	4196600	9.37315	24-HR	9TH	0.33367	9.03948	9.37315
494300	4196700	9.27595	24-HR	9TH	0.60147	8.67448	9.27595
494300	4196800	9.31188	24-HR	9TH	0.26505	9.04682	9.31188
494300	4196900	9.24515	24-HR	9TH	0.42325	8.8219	9.24515
494400	4196400	9.10449	24-HR	9TH	0.05188	9.05261	9.10449
494400	4196500	9.20361	24-HR	9TH	0.13171	9.07189	9.20361
494400	4196600	9.39488	24-HR	9TH	0.34115	9.05373	9.39488
494400	4196700	9.35251	24-HR	9TH	0.52469	8.82782	9.35251
494400	4196800	9.354	24-HR	9TH	0.44493	8.90907	9.354
494400	4196900	9.26571	24-HR	9TH	0.46215	8.80356	9.26571
494400	4197000	9.10257	24-HR	9TH	0.53214	8.57042	9.10257
494500	4196400	8.99521	24-HR	9TH	0	0	0
494500	4196500	9.03538	24-HR	9TH	0.23015	8.80524	9.03538
494500	4196600	9.28678	24-HR	9TH	0.14797	9.13881	9.28678
494500	4196700	9.32474	24-HR	9TH	0.36596	8.95878	9.32474
494500	4196800	9.39251	24-HR	9TH	0.22737	9.16514	9.39251
494500	4196900	9.26238	24-HR	9TH	0.47765	8.78473	9.26238
494500	4197000	9.16267	24-HR	9TH	0.556	8.60667	9.16267
494600	4196400	9.02271	24-HR	9TH	0.22093	8.80178	9.02271
494600	4196500	8.94489	24-HR	9TH	0	0	0
494600	4196600	9.12104	24-HR	9TH	0.11005	9.01099	9.12104
494600	4196700	9.26174	24-HR	9TH	0.18277	9.07897	9.26174
494600	4196800	9.35386	24-HR	9TH	0.21138	9.14248	9.35386
494600	4196900	9.24196	24-HR	9TH	0.5462	8.69576	9.24196
494600	4197000	9.15994	24-HR	9TH	0.73263	8.42731	9.15994
494600	4197100	9.03102	24-HR	9TH	0.44415	8.58687	9.03102
494700	4196500	8.85425	24-HR	9TH	0	0	0
494700	4196600	8.96874	24-HR	9TH	0	0	0
494700	4196700	9.05443	24-HR	9TH	0.3524	8.70203	9.05443
494700	4196800	9.41018	24-HR	9TH	0.42242	8.98775	9.41018
494700	4196900	9.1703	24-HR	9TH	0.51039	8.6599	9.1703
494700	4197000	9.11981	24-HR	9TH	0.52214	8.59766	9.11981
494700	4197100	9.05359	24-HR	9TH	0.54077	8.51282	9.05359
494800	4196700	8.98918	24-HR	9TH	0	0	0
494800	4196800	9.38112	24-HR	9TH	0.39785	8.98328	9.38112
494800	4197200	9.16899	24-HR	9TH	0.47719	8.6918	9.16899
494806	4196692.8	8.97381	24-HR	9TH	0	0	0
494806	4196791.2	9.36007	24-HR	9TH	0.29974	9.06032	9.36007
494806	4197184.8	9.14956	24-HR	9TH	0.42512	8.72444	9.14956
494968.8	4197480	8.89985	24-HR	9TH	0	0	0
495050.2	4197480	8.98251	24-HR	9TH	0	0	0

495100	4197500	8.89358	24-HR	9TH	0	0	0
495131.6	4197480	8.96444	24-HR	9TH	0	0	0
495200	4197600	8.86424	24-HR	9TH	0	0	0
495221.2	4197567.4	8.88013	24-HR	9TH	0	0	0
495221.3	4197656.9	8.90986	24-HR	9TH	0	0	0
495221.3	4197746.4	8.94973	24-HR	9TH	0	0	0
494100	4196500	9.06815	24-HR	9TH	0.11546	8.95269	9.06815
495100	4197600	8.81395	24-HR	9TH	0	0	0
495200	4197500	8.98716	24-HR	9TH	0	0	0
495200	4197700	8.91279	24-HR	9TH	0	0	0
495213	4197480	9.07066	24-HR	9TH	0.53122	8.53944	9.07066
495221.2	4197478	9.08735	24-HR	9TH	0.59984	8.48751	9.08735
494100	4196600	8.95659	24-HR	10TH	0	0	0
494200	4196400	8.83141	24-HR	10TH	0	0	0
494200	4196500	8.79282	24-HR	10TH	0	0	0
494200	4196600	8.87061	24-HR	10TH	0	0	0
494200	4196700	8.93739	24-HR	10TH	0	0	0
494200	4196800	8.88375	24-HR	10TH	0	0	0
494300	4196400	8.8421	24-HR	10TH	0	0	0
494300	4196500	8.85875	24-HR	10TH	0	0	0
494300	4196600	8.86142	24-HR	10TH	0	0	0
494300	4196700	9.12429	24-HR	10TH	0.38522	8.73907	9.12429
494300	4196800	8.72706	24-HR	10TH	0	0	0
494300	4196900	8.80363	24-HR	10TH	0	0	0
494400	4196400	8.94305	24-HR	10TH	0	0	0
494400	4196500	8.96759	24-HR	10TH	0	0	0
494400	4196600	8.92346	24-HR	10TH	0	0	0
494400	4196700	9.14497	24-HR	10TH	0.46304	8.68193	9.14497
494400	4196800	8.75819	24-HR	10TH	0	0	0
494400	4196900	8.7838	24-HR	10TH	0	0	0
494400	4197000	8.82504	24-HR	10TH	0	0	0
494500	4196400	8.91349	24-HR	10TH	0	0	0
494500	4196500	8.91191	24-HR	10TH	0	0	0
494500	4196600	9.00773	24-HR	10TH	0.53182	8.47591	9.00773
494500	4196700	9.12407	24-HR	10TH	0.49679	8.62728	9.12407
494500	4196800	8.97004	24-HR	10TH	0	0	0
494500	4196900	8.8204	24-HR	10TH	0	0	0
494500	4197000	8.7503	24-HR	10TH	0	0	0
494600	4196400	8.81745	24-HR	10TH	0	0	0
494600	4196500	8.81021	24-HR	10TH	0	0	0
494600	4196600	8.94622	24-HR	10TH	0	0	0
494600	4196700	8.96808	24-HR	10TH	0	0	0
494600	4196800	9.14564	24-HR	10TH	0.38337	8.76227	9.14564
494600	4196900	8.86308	24-HR	10TH	0	0	0
494600	4197000	8.81715	24-HR	10TH	0	0	0
494600	4197100	8.83069	24-HR	10TH	0	0	0
494700	4196500	8.67215	24-HR	10TH	0	0	0
494700	4196600	8.7352	24-HR	10TH	0	0	0
494700	4196700	8.84716	24-HR	10TH	0	0	0

494700	4196800	9.15604	24-HR	10TH	0.34038	8.81566	9.15604
494700	4196900	8.96071	24-HR	10TH	0	0	0
494700	4197000	8.969	24-HR	10TH	0	0	0
494700	4197100	8.90759	24-HR	10TH	0	0	0
494800	4196700	8.7653	24-HR	10TH	0	0	0
494800	4196800	9.19998	24-HR	10TH	0.23359	8.96639	9.19998
494800	4197200	8.86378	24-HR	10TH	0	0	0
494806	4196692.8	8.74318	24-HR	10TH	0	0	0
494806	4196791.2	9.21306	24-HR	10TH	0.23581	8.97725	9.21306
494806	4197184.8	8.88152	24-HR	10TH	0	0	0
494968.8	4197480	8.49226	24-HR	10TH	0	0	0
495050.2	4197480	8.74213	24-HR	10TH	0	0	0
495100	4197500	8.81201	24-HR	10TH	0	0	0
495131.6	4197480	8.85392	24-HR	10TH	0	0	0
495200	4197600	8.49797	24-HR	10TH	0	0	0
495221.2	4197567.4	8.56186	24-HR	10TH	0	0	0
495221.3	4197656.9	8.61056	24-HR	10TH	0	0	0
495221.3	4197746.4	8.71244	24-HR	10TH	0	0	0
494100	4196500	8.76839	24-HR	10TH	0	0	0
495100	4197600	8.50646	24-HR	10TH	0	0	0
495200	4197500	8.82096	24-HR	10TH	0	0	0
495200	4197700	8.64734	24-HR	10TH	0	0	0
495213	4197480	8.84547	24-HR	10TH	0	0	0
495221.2	4197478	8.84295	24-HR	10TH	0	0	0
494100	4196600	8.68247	24-HR	11TH	0	0	0
494200	4196400	8.5876	24-HR	11TH	0	0	0
494200	4196500	8.53339	24-HR	11TH	0	0	0
494200	4196600	8.65405	24-HR	11TH	0	0	0
494200	4196700	8.73114	24-HR	11TH	0	0	0
494200	4196800	8.43103	24-HR	11TH	0	0	0
494300	4196400	8.68735	24-HR	11TH	0	0	0
494300	4196500	8.63294	24-HR	11TH	0	0	0
494300	4196600	8.63173	24-HR	11TH	0	0	0
494300	4196700	8.66909	24-HR	11TH	0	0	0
494300	4196800	8.56297	24-HR	11TH	0	0	0
494300	4196900	8.35785	24-HR	11TH	0	0	0
494400	4196400	8.77248	24-HR	11TH	0	0	0
494400	4196500	8.63087	24-HR	11TH	0	0	0
494400	4196600	8.62677	24-HR	11TH	0	0	0
494400	4196700	8.77211	24-HR	11TH	0	0	0
494400	4196800	8.60351	24-HR	11TH	0	0	0
494400	4196900	8.36615	24-HR	11TH	0	0	0
494400	4197000	8.32575	24-HR	11TH	0	0	0
494500	4196400	8.72982	24-HR	11TH	0	0	0
494500	4196500	8.61256	24-HR	11TH	0	0	0
494500	4196600	8.58054	24-HR	11TH	0	0	0
494500	4196700	8.82497	24-HR	11TH	0	0	0
494500	4196800	8.67081	24-HR	11TH	0	0	0
494500	4196900	8.53083	24-HR	11TH	0	0	0

494500	4197000	8.3906	24-HR	11TH	0	0	0
494600	4196400	8.59205	24-HR	11TH	0	0	0
494600	4196500	8.55753	24-HR	11TH	0	0	0
494600	4196600	8.49837	24-HR	11TH	0	0	0
494600	4196700	8.79884	24-HR	11TH	0	0	0
494600	4196800	8.76826	24-HR	11TH	0	0	0
494600	4196900	8.73046	24-HR	11TH	0	0	0
494600	4197000	8.48347	24-HR	11TH	0	0	0
494600	4197100	8.19354	24-HR	11TH	0	0	0
494700	4196500	8.42209	24-HR	11TH	0	0	0
494700	4196600	8.53855	24-HR	11TH	0	0	0
494700	4196700	8.77972	24-HR	11TH	0	0	0
494700	4196800	8.77768	24-HR	11TH	0	0	0
494700	4196900	8.82973	24-HR	11TH	0	0	0
494700	4197000	8.54035	24-HR	11TH	0	0	0
494700	4197100	8.35616	24-HR	11TH	0	0	0
494800	4196700	8.66805	24-HR	11TH	0	0	0
494800	4196800	8.71927	24-HR	11TH	0	0	0
494800	4197200	8.43635	24-HR	11TH	0	0	0
494806	4196692.8	8.60879	24-HR	11TH	0	0	0
494806	4196791.2	8.73077	24-HR	11TH	0	0	0
494806	4197184.8	8.46037	24-HR	11TH	0	0	0
494968.8	4197480	8.2696	24-HR	11TH	0	0	0
495050.2	4197480	8.41126	24-HR	11TH	0	0	0
495100	4197500	8.52319	24-HR	11TH	0	0	0
495131.6	4197480	8.53939	24-HR	11TH	0	0	0
495200	4197600	8.40723	24-HR	11TH	0	0	0
495221.2	4197567.4	8.53014	24-HR	11TH	0	0	0
495221.3	4197656.9	8.38121	24-HR	11TH	0	0	0
495221.3	4197746.4	8.39214	24-HR	11TH	0	0	0
494100	4196500	8.53923	24-HR	11TH	0	0	0
495100	4197600	8.38985	24-HR	11TH	0	0	0
495200	4197500	8.56897	24-HR	11TH	0	0	0
495200	4197700	8.41832	24-HR	11TH	0	0	0
495213	4197480	8.60096	24-HR	11TH	0	0	0
495221.2	4197478	8.6079	24-HR	11TH	0	0	0

24-Hour $PM_{2.5}$ Culpability Analysis For Train Delivery

X	Y	AVERAGE CONC	AVE	RANK	IG TRAIN	INVENTORY	IG TRAIN + INVENTORY
494100	4196600	16.33261	24-HR	1ST	0.21549	16.11712	16.33261
494200	4196400	17.27766	24-HR	1ST	0.277	17.00065	17.27766

494200	4196500	16.99907	24-HR	1ST	0.26442	16.73465	16.99907	
494200	4196600	16.54672	24-HR	1ST	0.22906	16.31766	16.54672	
494200	4196700	16.17611	24-HR	1ST	0.21943	15.95668	16.17611	
494200	4196800	15.75548	24-HR	1ST	0.32094	15.43454	15.75548	
494300	4196400	17.53092	24-HR	1ST	0.28777	17.24315	17.53092	
494300	4196500	17.21985	24-HR	1ST	0.30422	16.91563	17.21985	
494300	4196600	16.69266	24-HR	1ST	0.29219	16.40047	16.69266	
494300	4196700	16.32092	24-HR	1ST	0.24689	16.07404	16.32092	
494300	4196800	16.00175	24-HR	1ST	0.3338	15.66795	16.00175	
494300	4196900	16.02487	24-HR	1ST	0.39359	15.63128	16.02487	
494400	4196400	17.68864	24-HR	1ST	0.26036	17.42828	17.68864	
494400	4196500	17.41434	24-HR	1ST	0.32555	17.08879	17.41434	
494400	4196600	16.90866	24-HR	1ST	0.33991	16.56875	16.90866	
494400	4196700	16.46276	24-HR	1ST	0.27016	16.19261	16.46276	
494400	4196800	16.18832	24-HR	1ST	0.34729	15.84103	16.18832	
494400	4196900	16.10506	24-HR	1ST	0.3886	15.71647	16.10506	
494400	4197000	16.26767	24-HR	1ST	0.419	15.84867	16.26767	
494500	4196400	17.75829	24-HR	1ST	0.19683	17.56146	17.75829	
494500	4196500	17.51493	24-HR	1ST	0.29409	17.22084	17.51493	
494500	4196600	17.08197	24-HR	1ST	0.37226	16.70971	17.08197	
494500	4196700	16.55675	24-HR	1ST	0.29435	16.26239	16.55675	
494500	4196800	16.34646	24-HR	1ST	0.37506	15.97139	16.34646	
494500	4196900	16.18052	24-HR	1ST	0.37878	15.80174	16.18052	
494500	4197000	16.3069	24-HR	1ST	0.41742	15.88947	16.3069	
494600	4196400	17.82006	24-HR	1ST	0.14493	17.67514	17.82006	Max IG Train + Inventory
494600	4196500	17.56423	24-HR	1ST	0.21785	17.34639	17.56423	
494600	4196600	17.17759	24-HR	1ST	0.32071	16.85689	17.17759	
494600	4196700	16.65675	24-HR	1ST	0.35776	16.29899	16.65675	
494600	4196800	16.48716	24-HR	1ST	0.40745	16.07971	16.48716	
494600	4196900	16.28187	24-HR	1ST	0.36557	15.9163	16.28187	
494600	4197000	16.29006	24-HR	1ST	0.39158	15.89848	16.29006	
494600	4197100	16.4561	24-HR	1ST	0.39009	16.06602	16.4561	
494700	4196500	17.64363	24-HR	1ST	0.15105	17.49257	17.64363	
494700	4196600	17.25821	24-HR	1ST	0.22877	17.02943	17.25821	
494700	4196700	16.72862	24-HR	1ST	0.2939	16.43472	16.72862	
494700	4196800	16.59493	24-HR	1ST	0.47718	16.11775	16.59493	
494700	4196900	16.35982	24-HR	1ST	0.34988	16.00994	16.35982	

494700	4197000	16.2366	24-HR	1ST	0.37267	15.86393	16.2366
494700	4197100	16.45046	24-HR	1ST	0.38607	16.06439	16.45046
494800	4196700	16.79465	24-HR	1ST	0.3319	16.46276	16.79465
494800	4196800	16.72717	24-HR	1ST	0.44886	16.27831	16.72717
494800	4197200	16.72129	24-HR	1ST	0.35095	16.37034	16.72129
494806	4196693	16.83988	24-HR	1ST	0.20804	16.63184	16.83988
494806	4196791	16.78609	24-HR	1ST	0.47734	16.30875	16.78609
494806	4197185	16.68703	24-HR	1ST	0.35566	16.33137	16.68703
494968.8	4197480	17.23148	24-HR	1ST	0.39692	16.83457	17.23148
495050.2	4197480	17.40342	24-HR	1ST	0.57037	16.83305	17.40342
495100	4197500	17.49382	24-HR	1ST	0.63128	16.86254	17.49382
495131.6	4197480	17.48743	24-HR	1ST	0.6437	16.84373	17.48743
495200	4197600	17.53944	24-HR	1ST	0.56766	16.97178	17.53944
495221.2	4197567	17.52014	24-HR	1ST	0.57483	16.94532	17.52014
495221.3	4197657	17.50817	24-HR	1ST	0.51076	16.99742	17.50817
495221.3	4197746	17.41529	24-HR	1ST	0.47609	16.9392	17.41529
494100	4196500	16.77294	24-HR	1ST	0.28025	16.49269	16.77294
495100	4197600	17.50253	24-HR	1ST	0.55122	16.95131	17.50253
495200	4197500	17.52778	24-HR	1ST	0.57191	16.95587	17.52778
495200	4197700	17.4577	24-HR	1ST	0.47342	16.98427	17.4577
495213	4197480	17.53493	24-HR	1ST	0.58148	16.95345	17.53493
495221.2	4197478	17.54035	24-HR	1ST	0.58222	16.95814	17.54035
494100	4196600	14.30483	24-HR	2ND	0.24343	14.0614	14.30483
494200	4196400	14.31453	24-HR	2ND	0.1973	14.11723	14.31453
494200	4196500	14.42621	24-HR	2ND	0.2091	14.21711	14.42621
494200	4196600	14.45331	24-HR	2ND	0.24316	14.21015	14.45331
494200	4196700	14.05961	24-HR	2ND	0.35124	13.70837	14.05961
494200	4196800	13.9728	24-HR	2ND	0.33025	13.64255	13.9728
494300	4196400	14.34251	24-HR	2ND	0.19013	14.15238	14.34251
494300	4196500	14.50024	24-HR	2ND	0.22148	14.27875	14.50024
494300	4196600	14.579	24-HR	2ND	0.2331	14.3459	14.579
494300	4196700	14.11703	24-HR	2ND	0.28569	13.83135	14.11703
494300	4196800	13.93663	24-HR	2ND	0.34143	13.5952	13.93663
494300	4196900	13.36727	24-HR	2ND	0.36659	13.00069	13.36727
494400	4196400	14.22759	24-HR	2ND	0.16677	14.06082	14.22759
494400	4196500	14.39992	24-HR	2ND	0.23192	14.168	14.39992
494400	4196600	14.47843	24-HR	2ND	0.24766	14.23077	14.47843

494400	4196700	14.08253	24-HR	2ND	0.38844	13.69409	14.08253
494400	4196800	13.79599	24-HR	2ND	0.27404	13.52195	13.79599
494400	4196900	13.29593	24-HR	2ND	0.33855	12.95738	13.29593
494400	4197000	12.63647	24-HR	2ND	0.39274	12.24373	12.63647
494500	4196400	14.116	24-HR	2ND	0.1448	13.9712	14.116
494500	4196500	14.30055	24-HR	2ND	0.23778	14.06278	14.30055
494500	4196600	14.40197	24-HR	2ND	0.30475	14.09722	14.40197
494500	4196700	14.13718	24-HR	2ND	0.50079	13.63639	14.13718
494500	4196800	13.73617	24-HR	2ND	0.35485	13.38132	13.73617
494500	4196900	13.18956	24-HR	2ND	0.38518	12.80439	13.18956
494500	4197000	12.6274	24-HR	2ND	0.47893	12.14847	12.6274
494600	4196400	14.06503	24-HR	2ND	0.13063	13.9344	14.06503
494600	4196500	14.20937	24-HR	2ND	0.19792	14.01145	14.20937
494600	4196600	14.30539	24-HR	2ND	0.25667	14.04872	14.30539
494600	4196700	14.1496	24-HR	2ND	0.42481	13.72479	14.1496
494600	4196800	13.80948	24-HR	2ND	0.39998	13.4095	13.80948
494600	4196900	13.2103	24-HR	2ND	0.34152	12.86878	13.2103
494600	4197000	12.71921	24-HR	2ND	0.34042	12.37879	12.71921
494600	4197100	12.86847	24-HR	2ND	0.3566	12.51187	12.86847
494700	4196500	14.13135	24-HR	2ND	0.17744	13.95391	14.13135
494700	4196600	14.19066	24-HR	2ND	0.19737	13.99329	14.19066
494700	4196700	14.07767	24-HR	2ND	0.37328	13.70439	14.07767
494700	4196800	13.84474	24-HR	2ND	0.40013	13.44461	13.84474
494700	4196900	13.25358	24-HR	2ND	0.34536	12.90823	13.25358
494700	4197000	12.83966	24-HR	2ND	0.31118	12.52847	12.83966
494700	4197100	12.91191	24-HR	2ND	0.30477	12.60715	12.91191
494800	4196700	13.98693	24-HR	2ND	0.21652	13.77041	13.98693
494800	4196800	13.73895	24-HR	2ND	0.29238	13.44657	13.73895
494800	4197200	12.98592	24-HR	2ND	0.29742	12.6885	12.98592
494806	4196693	13.99177	24-HR	2ND	0.18749	13.80429	13.99177
494806	4196791	13.7814	24-HR	2ND	0.30219	13.47921	13.7814
494806	4197185	12.98673	24-HR	2ND	0.30596	12.68077	12.98673
494968.8	4197480	13.43098	24-HR	2ND	0.24711	13.18386	13.43098
495050.2	4197480	13.66171	24-HR	2ND	0.3879	13.27381	13.66171
495100	4197500	13.77471	24-HR	2ND	0.45046	13.32425	13.77471
495131.6	4197480	13.72663	24-HR	2ND	0.44186	13.28477	13.72663
495200	4197600	13.83784	24-HR	2ND	0.39339	13.44444	13.83784

495221.2	4197567	13.83893	24-HR	2ND	0.39191	13.44703	13.83893
495221.3	4197657	13.8145	24-HR	2ND	0.39712	13.41738	13.8145
495221.3	4197746	13.62726	24-HR	2ND	0.43403	13.19323	13.62726
494100	4196500	14.35686	24-HR	2ND	0.19856	14.1583	14.35686
495100	4197600	13.85808	24-HR	2ND	0.44077	13.41731	13.85808
495200	4197500	13.76845	24-HR	2ND	0.49589	13.27257	13.76845
495200	4197700	13.74859	24-HR	2ND	0.44349	13.3051	13.74859
495213	4197480	13.71808	24-HR	2ND	0.50027	13.21781	13.71808
495221.2	4197478	13.70809	24-HR	2ND	0.49993	13.20816	13.70809
494100	4196600	12.19527	24-HR	3RD	0.29909	11.89618	12.19527
494200	4196400	12.08965	24-HR	3RD	0.34516	11.74448	12.08965
494200	4196500	12.23476	24-HR	3RD	0.36595	11.86881	12.23476
494200	4196600	12.34003	24-HR	3RD	0.42048	11.91955	12.34003
494200	4196700	12.68373	24-HR	3RD	0.33787	12.34587	12.68373
494200	4196800	12.59656	24-HR	3RD	0.26627	12.33029	12.59656
494300	4196400	12.03741	24-HR	3RD	0.33416	11.70326	12.03741
494300	4196500	12.22701	24-HR	3RD	0.38899	11.83802	12.22701
494300	4196600	12.41977	24-HR	3RD	0.47189	11.94787	12.41977
494300	4196700	12.84515	24-HR	3RD	0.46595	12.3792	12.84515
494300	4196800	12.57421	24-HR	3RD	0.36466	12.20955	12.57421
494300	4196900	12.56765	24-HR	3RD	0.21344	12.35421	12.56765
494400	4196400	11.92496	24-HR	3RD	0.30188	11.62308	11.92496
494400	4196500	12.13147	24-HR	3RD	0.43406	11.69741	12.13147
494400	4196600	12.46563	24-HR	3RD	0.54485	11.92078	12.46563
494400	4196700	12.94965	24-HR	3RD	0.46995	12.4797	12.94965
494400	4196800	12.63124	24-HR	3RD	0.43594	12.1953	12.63124
494400	4196900	12.53058	24-HR	3RD	0.42873	12.10185	12.53058
494400	4197000	12.45845	24-HR	3RD	0.40244	12.05601	12.45845
494500	4196400	11.83711	24-HR	3RD	0.28014	11.55697	11.83711
494500	4196500	11.97349	24-HR	3RD	0.39823	11.57526	11.97349
494500	4196600	12.35728	24-HR	3RD	0.426	11.93129	12.35728
494500	4196700	12.93815	24-HR	3RD	0.39232	12.54582	12.93815
494500	4196800	12.68685	24-HR	3RD	0.36499	12.32186	12.68685
494500	4196900	12.58725	24-HR	3RD	0.30905	12.27821	12.58725
494500	4197000	12.49013	24-HR	3RD	0.27265	12.21748	12.49013
494600	4196400	11.80741	24-HR	3RD	0.21789	11.58952	11.80741
494600	4196500	11.84674	24-HR	3RD	0.38574	11.461	11.84674

494600	4196600	12.23772	24-HR	3RD	0.34821	11.8895	12.23772
494600	4196700	12.85001	24-HR	3RD	0.36485	12.48516	12.85001
494600	4196800	12.6896	24-HR	3RD	0.39721	12.2924	12.6896
494600	4196900	12.5732	24-HR	3RD	0.35595	12.21724	12.5732
494600	4197000	12.54832	24-HR	3RD	0.42535	12.12297	12.54832
494600	4197100	12.25398	24-HR	3RD	0.44396	11.81002	12.25398
494700	4196500	11.98439	24-HR	3RD	0.12934	11.85504	11.98439
494700	4196600	12.34412	24-HR	3RD	0.25103	12.09309	12.34412
494700	4196700	12.8582	24-HR	3RD	0.21858	12.63962	12.8582
494700	4196800	12.73726	24-HR	3RD	0.2668	12.47046	12.73726
494700	4196900	12.62239	24-HR	3RD	0.30735	12.31505	12.62239
494700	4197000	12.57001	24-HR	3RD	0.31953	12.25048	12.57001
494700	4197100	12.36263	24-HR	3RD	0.45771	11.90491	12.36263
494800	4196700	13.05741	24-HR	3RD	0.15047	12.90695	13.05741
494800	4196800	12.89287	24-HR	3RD	0.24188	12.65099	12.89287
494800	4197200	12.1185	24-HR	3RD	0.19489	11.92361	12.1185
494806	4196693	13.02681	24-HR	3RD	0.26216	12.76465	13.02681
494806	4196791	12.96579	24-HR	3RD	0.37091	12.59488	12.96579
494806	4197185	12.14849	24-HR	3RD	0.19328	11.95521	12.14849
494968.8	4197480	11.92474	24-HR	3RD	0.32281	11.60193	11.92474
495050.2	4197480	12.24157	24-HR	3RD	0.42862	11.81295	12.24157
495100	4197500	12.33894	24-HR	3RD	0.44786	11.89109	12.33894
495131.6	4197480	12.45834	24-HR	3RD	0.46868	11.98967	12.45834
495200	4197600	12.28834	24-HR	3RD	0.46689	11.82146	12.28834
495221.2	4197567	12.36907	24-HR	3RD	0.48477	11.8843	12.36907
495221.3	4197657	12.16695	24-HR	3RD	0.44908	11.71786	12.16695
495221.3	4197746	11.99241	24-HR	3RD	0.36023	11.63218	11.99241
494100	4196500	12.03789	24-HR	3RD	0.27949	11.7584	12.03789
495100	4197600	12.0405	24-HR	3RD	0.35823	11.68228	12.0405
495200	4197500	12.48732	24-HR	3RD	0.48936	11.99796	12.48732
495200	4197700	12.03205	24-HR	3RD	0.37315	11.6589	12.03205
495213	4197480	12.52332	24-HR	3RD	0.49578	12.02754	12.52332
494100	4196600	11.75577	24-HR	4TH	0.26455	11.49122	11.75577
494200	4196400	11.07522	24-HR	4TH	0.12039	10.95483	11.07522
494200	4196500	11.42826	24-HR	4TH	0.18646	11.24181	11.42826
494200	4196600	11.75129	24-HR	4TH	0.23049	11.5208	11.75129
494200	4196700	11.79805	24-HR	4TH	0.17381	11.62424	11.79805

494200	4196800	11.96105	24-HR	4TH	0.18509	11.77596	11.96105
494300	4196400	11.25347	24-HR	4TH	0.2329	11.02056	11.25347
494300	4196500	11.46984	24-HR	4TH	0.18366	11.28618	11.46984
494300	4196600	11.78374	24-HR	4TH	0.24461	11.53913	11.78374
494300	4196700	11.77295	24-HR	4TH	0.17781	11.59514	11.77295
494300	4196800	11.9631	24-HR	4TH	0.12464	11.83846	11.9631
494300	4196900	11.96871	24-HR	4TH	0.31099	11.65771	11.96871
494400	4196400	11.37654	24-HR	4TH	0.1497	11.22684	11.37654
494400	4196500	11.44794	24-HR	4TH	0.12495	11.32299	11.44794
494400	4196600	11.76573	24-HR	4TH	0.22831	11.53742	11.76573
494400	4196700	11.75785	24-HR	4TH	0.18993	11.56792	11.75785
494400	4196800	11.90315	24-HR	4TH	0.15702	11.74613	11.90315
494400	4196900	11.94265	24-HR	4TH	0.1486	11.79405	11.94265
494400	4197000	12.09111	24-HR	4TH	0.21608	11.87502	12.09111
494500	4196400	11.3906	24-HR	4TH	0.09635	11.29425	11.3906
494500	4196500	11.30637	24-HR	4TH	0.05365	11.25272	11.30637
494500	4196600	11.63987	24-HR	4TH	0.26052	11.37935	11.63987
494500	4196700	11.64282	24-HR	4TH	0.20922	11.4336	11.64282
494500	4196800	11.79559	24-HR	4TH	0.29413	11.50145	11.79559
494500	4196900	11.85936	24-HR	4TH	0.20938	11.64998	11.85936
494500	4197000	12.03981	24-HR	4TH	0.36826	11.67155	12.03981
494600	4196400	11.44179	24-HR	4TH	0.13423	11.30756	11.44179
494600	4196500	11.41863	24-HR	4TH	0.05543	11.36319	11.41863
494600	4196600	11.58788	24-HR	4TH	0.17719	11.4107	11.58788
494600	4196700	11.49658	24-HR	4TH	0.17752	11.31906	11.49658
494600	4196800	11.72736	24-HR	4TH	0.31009	11.41727	11.72736
494600	4196900	11.85134	24-HR	4TH	0.09271	11.75863	11.85134
494600	4197000	11.98817	24-HR	4TH	0.23939	11.74878	11.98817
494600	4197100	11.84529	24-HR	4TH	0.46477	11.38052	11.84529
494700	4196500	11.52716	24-HR	4TH	0.31055	11.21661	11.52716
494700	4196600	11.64389	24-HR	4TH	0.22934	11.41455	11.64389
494700	4196700	11.58833	24-HR	4TH	0.0806	11.50774	11.58833
494700	4196800	11.79136	24-HR	4TH	0.22144	11.56993	11.79136
494700	4196900	11.83017	24-HR	4TH	0.14395	11.68622	11.83017
494700	4197000	12.04433	24-HR	4TH	0.30966	11.73467	12.04433
494700	4197100	11.93424	24-HR	4TH	0.32529	11.60894	11.93424
494800	4196700	11.67839	24-HR	4TH	0.06804	11.61035	11.67839

494800	4196800	12.07186	24-HR	4TH	0.29923	11.77263	12.07186
494800	4197200	11.61427	24-HR	4TH	0.30827	11.306	11.61427
494806	4196693	11.67135	24-HR	4TH	0.06311	11.60824	11.67135
494806	4196791	12.10176	24-HR	4TH	0.23258	11.86918	12.10176
494806	4197185	11.70831	24-HR	4TH	0.31471	11.3936	11.70831
494968.8	4197480	11.0447	24-HR	4TH	0.29235	10.75235	11.0447
495050.2	4197480	11.11912	24-HR	4TH	0.42346	10.69566	11.11912
495100	4197500	11.16632	24-HR	4TH	0.32482	10.8415	11.16632
495131.6	4197480	11.24118	24-HR	4TH	0.44272	10.79846	11.24118
495200	4197600	11.32111	24-HR	4TH	0.26795	11.05317	11.32111
495221.2	4197567	11.32778	24-HR	4TH	0.28855	11.03923	11.32778
495221.3	4197657	11.29635	24-HR	4TH	0.23277	11.06358	11.29635
495221.3	4197746	11.2488	24-HR	4TH	0.38037	10.86843	11.2488
494100	4196500	11.42835	24-HR	4TH	0.19158	11.23678	11.42835
495100	4197600	11.24286	24-HR	4TH	0.20073	11.04213	11.24286
495200	4197500	11.32623	24-HR	4TH	0.44451	10.88172	11.32623
495200	4197700	11.25317	24-HR	4TH	0.25214	11.00103	11.25317
495213	4197480	11.36649	24-HR	4TH	0.44941	10.91708	11.36649
495221.2	4197478	11.37776	24-HR	4TH	0.44693	10.93083	11.37776
494100	4196600	10.99841	24-HR	5TH	0.07396	10.92446	10.99841
494200	4196400	10.61704	24-HR	5TH	0.20162	10.41542	10.61704
494200	4196500	10.69928	24-HR	5TH	0.13042	10.56886	10.69928
494200	4196600	11.03739	24-HR	5TH	0.0784	10.95899	11.03739
494200	4196700	11.34525	24-HR	5TH	0.16298	11.18227	11.34525
494200	4196800	11.13076	24-HR	5TH	0.14438	10.98638	11.13076
494300	4196400	10.72207	24-HR	5TH	0.10616	10.61591	10.72207
494300	4196500	10.85008	24-HR	5TH	0.13601	10.71407	10.85008
494300	4196600	11.03826	24-HR	5TH	0.07561	10.96265	11.03826
494300	4196700	11.30806	24-HR	5TH	0.17131	11.13676	11.30806
494300	4196800	11.14169	24-HR	5TH	0.15929	10.9824	11.14169
494300	4196900	10.9998	24-HR	5TH	0.1768	10.823	10.9998
494400	4196400	10.76656	24-HR	5TH	0.19879	10.56777	10.76656
494400	4196500	10.99249	24-HR	5TH	0.10982	10.88267	10.99249
494400	4196600	10.99298	24-HR	5TH	0.05288	10.9401	10.99298
494400	4196700	11.29468	24-HR	5TH	0.19404	11.10064	11.29468
494400	4196800	11.10083	24-HR	5TH	0.23227	10.86855	11.10083
494400	4196900	10.98653	24-HR	5TH	0.17997	10.80656	10.98653

494400	4197000	11.08021	24-HR	5TH	0.22305	10.85716	11.08021
494500	4196400	10.68324	24-HR	5TH	0.23314	10.4501	10.68324
494500	4196500	11.10063	24-HR	5TH	0.13325	10.96737	11.10063
494500	4196600	11.10689	24-HR	5TH	0.04973	11.05716	11.10689
494500	4196700	11.25839	24-HR	5TH	0.28369	10.9747	11.25839
494500	4196800	11.10688	24-HR	5TH	0.18555	10.92134	11.10688
494500	4196900	10.99017	24-HR	5TH	0.28127	10.7089	10.99017
494500	4197000	11.0296	24-HR	5TH	0.12513	10.90447	11.0296
494600	4196400	10.67762	24-HR	5TH	0.1441	10.53352	10.67762
494600	4196500	11.05847	24-HR	5TH	0.10065	10.95783	11.05847
494600	4196600	11.13369	24-HR	5TH	0.10593	11.02776	11.13369
494600	4196700	11.31448	24-HR	5TH	0.2462	11.06828	11.31448
494600	4196800	11.15466	24-HR	5TH	0.24385	10.91081	11.15466
494600	4196900	10.95406	24-HR	5TH	0.4035	10.55055	10.95406
494600	4197000	10.96492	24-HR	5TH	0.31181	10.65311	10.96492
494600	4197100	10.88503	24-HR	5TH	0.16128	10.72375	10.88503
494700	4196500	11.02185	24-HR	5TH	0.07448	10.94737	11.02185
494700	4196600	11.20909	24-HR	5TH	0.08014	11.12895	11.20909
494700	4196700	11.40343	24-HR	5TH	0.2745	11.12893	11.40343
494700	4196800	11.26785	24-HR	5TH	0.26181	11.00604	11.26785
494700	4196900	11.15262	24-HR	5TH	0.28212	10.8705	11.15262
494700	4197000	11.13996	24-HR	5TH	0.16877	10.97119	11.13996
494700	4197100	10.97076	24-HR	5TH	0.16992	10.80084	10.97076
494800	4196700	11.45697	24-HR	5TH	0.2355	11.22146	11.45697
494800	4196800	11.30657	24-HR	5TH	0.28755	11.01902	11.30657
494800	4197200	10.82385	24-HR	5TH	0.26428	10.55957	10.82385
494806	4196693	11.46816	24-HR	5TH	0.23083	11.23733	11.46816
494806	4196791	11.34315	24-HR	5TH	0.31156	11.03159	11.34315
494806	4197185	10.89714	24-HR	5TH	0.27013	10.62701	10.89714
494968.8	4197480	10.67564	24-HR	5TH	0.42312	10.25252	10.67564
495050.2	4197480	10.81362	24-HR	5TH	0.44981	10.3638	10.81362
495100	4197500	10.6901	24-HR	5TH	0.50327	10.18683	10.6901
495131.6	4197480	10.77951	24-HR	5TH	0.44429	10.33523	10.77951
495200	4197600	10.41687	24-HR	5TH	0.40775	10.00912	10.41687
495221.2	4197567	10.52577	24-HR	5TH	0.38692	10.13885	10.52577
495221.3	4197657	10.45537	24-HR	5TH	0.36526	10.09011	10.45537
495221.3	4197746	10.40365	24-HR	5TH	0.39683	10.00683	10.40365

494100	4196500	10.5822	24-HR	5TH	0.05364	10.52857	10.5822
495100	4197600	10.20484	24-HR	5TH	0.43637	9.76846	10.20484
495200	4197500	10.84092	24-HR	5TH	0.33363	10.50728	10.84092
495200	4197700	10.42463	24-HR	5TH	0.45565	9.96898	10.42463
495213	4197480	10.9046	24-HR	5TH	0.33876	10.56584	10.9046
495221.2	4197478	10.91411	24-HR	5TH	0.33291	10.5812	10.91411
494100	4196600	10.42869	24-HR	6TH	0.1656	10.26308	10.42869
494200	4196400	10.06307	24-HR	6TH	0.3095	9.75357	10.06307
494200	4196500	10.31774	24-HR	6TH	0.17664	10.14111	10.31774
494200	4196600	10.44438	24-HR	6TH	0.19657	10.24781	10.44438
494200	4196700	10.6053	24-HR	6TH	0.19911	10.40619	10.6053
494200	4196800	10.61068	24-HR	6TH	0.15461	10.45607	10.61068
494300	4196400	9.91913	24-HR	6TH	0.36517	9.55396	9.91913
494300	4196500	10.23085	24-HR	6TH	0.31638	9.91447	10.23085
494300	4196600	10.40066	24-HR	6TH	0.24093	10.15973	10.40066
494300	4196700	10.59782	24-HR	6TH	0.26038	10.33744	10.59782
494300	4196800	10.62752	24-HR	6TH	0.18153	10.44599	10.62752
494300	4196900	10.47693	24-HR	6TH	0.1565	10.32043	10.47693
494400	4196400	9.81096	24-HR	6TH	0.14152	9.66944	9.81096
494400	4196500	10.16909	24-HR	6TH	0.23478	9.93431	10.16909
494400	4196600	10.47375	24-HR	6TH	0.22349	10.25026	10.47375
494400	4196700	10.51015	24-HR	6TH	0.30588	10.20427	10.51015
494400	4196800	10.62408	24-HR	6TH	0.26018	10.3639	10.62408
494400	4196900	10.47289	24-HR	6TH	0.17626	10.29663	10.47289
494400	4197000	10.48939	24-HR	6TH	0.26333	10.22605	10.48939
494500	4196400	9.91603	24-HR	6TH	0.10169	9.81434	9.91603
494500	4196500	10.16965	24-HR	6TH	0.26337	9.90628	10.16965
494500	4196600	10.49954	24-HR	6TH	0.15301	10.34652	10.49954
494500	4196700	10.57689	24-HR	6TH	0.15816	10.41874	10.57689
494500	4196800	10.64575	24-HR	6TH	0.18774	10.45801	10.64575
494500	4196900	10.53694	24-HR	6TH	0.08123	10.4557	10.53694
494500	4197000	10.55166	24-HR	6TH	0.20135	10.35032	10.55166
494600	4196400	9.77432	24-HR	6TH	0.15252	9.6218	9.77432
494600	4196500	10.13617	24-HR	6TH	0.19479	9.94138	10.13617
494600	4196600	10.62504	24-HR	6TH	0.16951	10.45553	10.62504
494600	4196700	10.66918	24-HR	6TH	0.19596	10.47323	10.66918
494600	4196800	10.74003	24-HR	6TH	0.28615	10.45387	10.74003

494600	4196900	10.65483	24-HR	6TH	0.09122	10.56361	10.65483
494600	4197000	10.64001	24-HR	6TH	0.11365	10.52636	10.64001
494600	4197100	10.44476	24-HR	6TH	0.14132	10.30344	10.44476
494700	4196500	9.99723	24-HR	6TH	0.06353	9.9337	9.99723
494700	4196600	10.45493	24-HR	6TH	0.11859	10.33635	10.45493
494700	4196700	10.60909	24-HR	6TH	0.20525	10.40384	10.60909
494700	4196800	10.68479	24-HR	6TH	0.3481	10.33669	10.68479
494700	4196900	10.51876	24-HR	6TH	0.09006	10.4287	10.51876
494700	4197000	10.45025	24-HR	6TH	0.20936	10.24089	10.45025
494700	4197100	10.31324	24-HR	6TH	0.32383	9.98941	10.31324
494800	4196700	10.48788	24-HR	6TH	0.1278	10.36008	10.48788
494800	4196800	10.54015	24-HR	6TH	0.31401	10.22614	10.54015
494800	4197200	10.16846	24-HR	6TH	0.13028	10.03819	10.16846
494806	4196693	10.47411	24-HR	6TH	0.10932	10.36479	10.47411
494806	4196791	10.52473	24-HR	6TH	0.29835	10.22637	10.52473
494806	4197185	10.15759	24-HR	6TH	0.13631	10.02128	10.15759
494968.8	4197480	9.79734	24-HR	6TH	0.37008	9.42727	9.79734
495050.2	4197480	9.89611	24-HR	6TH	0.56644	9.32967	9.89611
495100	4197500	9.89263	24-HR	6TH	0.57735	9.31529	9.89263
495131.6	4197480	9.92255	24-HR	6TH	0.56694	9.35561	9.92255
495200	4197600	9.82782	24-HR	6TH	0.51088	9.31694	9.82782
495221.2	4197567	9.89676	24-HR	6TH	0.55686	9.33991	9.89676
495221.3	4197657	9.76418	24-HR	6TH	0.65506	9.10913	9.76418
495221.3	4197746	9.86004	24-HR	6TH	0.31539	9.54465	9.86004
494100	4196500	10.36386	24-HR	6TH	0.38139	9.98246	10.36386
495100	4197600	9.79388	24-HR	6TH	0.42622	9.36765	9.79388
495200	4197500	9.95588	24-HR	6TH	0.6781	9.27778	9.95588
495200	4197700	9.81195	24-HR	6TH	0.44241	9.36955	9.81195
495213	4197480	9.98368	24-HR	6TH	0.66898	9.31469	9.98368
495221.2	4197478	9.98407	24-HR	6TH	0.65934	9.32473	9.98407
494100	4196600	9.82291	24-HR	7TH	0.26648	9.55644	9.82291
494200	4196400	9.78836	24-HR	7TH	0.29882	9.48953	9.78836
494200	4196500	9.92275	24-HR	7TH	0.40574	9.517	9.92275
494200	4196600	9.87661	24-HR	7TH	0.13738	9.73923	9.87661
494200	4196700	9.70894	24-HR	7TH	0.13731	9.57162	9.70894
494200	4196800	9.9129	24-HR	7TH	0.27372	9.63918	9.9129
494300	4196400	9.64718	24-HR	7TH	0.16636	9.48083	9.64718

494300	4196500	9.94523	24-HR	7TH	0.28741	9.65782	9.94523
494300	4196600	9.9438	24-HR	7TH	0.14083	9.80297	9.9438
494300	4196700	9.86944	24-HR	7TH	0.11049	9.75895	9.86944
494300	4196800	10.03459	24-HR	7TH	0.26437	9.77022	10.03459
494300	4196900	10.00531	24-HR	7TH	0.32785	9.67746	10.00531
494400	4196400	9.49038	24-HR	7TH	0.286	9.20438	9.49038
494400	4196500	9.87416	24-HR	7TH	0.3278	9.54636	9.87416
494400	4196600	9.96516	24-HR	7TH	0.26016	9.705	9.96516
494400	4196700	10.07109	24-HR	7TH	0.10984	9.96124	10.07109
494400	4196800	10.24461	24-HR	7TH	0.25944	9.98517	10.24461
494400	4196900	10.13356	24-HR	7TH	0.31469	9.81887	10.13356
494400	4197000	10.0677	24-HR	7TH	0.28132	9.78639	10.0677
494500	4196400	9.44053	24-HR	7TH	0.1734	9.26713	9.44053
494500	4196500	9.81046	24-HR	7TH	0.09771	9.71275	9.81046
494500	4196600	9.86912	24-HR	7TH	0.3079	9.56122	9.86912
494500	4196700	10.12021	24-HR	7TH	0.24968	9.87053	10.12021
494500	4196800	10.32395	24-HR	7TH	0.37816	9.94579	10.32395
494500	4196900	10.22054	24-HR	7TH	0.42704	9.7935	10.22054
494500	4197000	10.07379	24-HR	7TH	0.29744	9.77635	10.07379
494600	4196400	9.44564	24-HR	7TH	0.03355	9.4121	9.44564
494600	4196500	9.7873	24-HR	7TH	0.05183	9.73547	9.7873
494600	4196600	9.81638	24-HR	7TH	0.20439	9.61198	9.81638
494600	4196700	10.11988	24-HR	7TH	0.38877	9.73111	10.11988
494600	4196800	10.24165	24-HR	7TH	0.32451	9.91714	10.24165
494600	4196900	10.13188	24-HR	7TH	0.44358	9.6883	10.13188
494600	4197000	10.05967	24-HR	7TH	0.27411	9.78557	10.05967
494600	4197100	9.99583	24-HR	7TH	0.29252	9.70331	9.99583
494700	4196500	9.71951	24-HR	7TH	0.0807	9.63881	9.71951
494700	4196600	9.81005	24-HR	7TH	0.14072	9.66933	9.81005
494700	4196700	9.95709	24-HR	7TH	0.26149	9.69561	9.95709
494700	4196800	9.97954	24-HR	7TH	0.40072	9.57882	9.97954
494700	4196900	10.07168	24-HR	7TH	0.49925	9.57244	10.07168
494700	4197000	10.00101	24-HR	7TH	0.24343	9.75758	10.00101
494700	4197100	9.94066	24-HR	7TH	0.21475	9.72591	9.94066
494800	4196700	9.8375	24-HR	7TH	0.18933	9.64817	9.8375
494800	4196800	9.88616	24-HR	7TH	0.22583	9.66032	9.88616
494800	4197200	9.73585	24-HR	7TH	0.37414	9.36171	9.73585

494806	4196693	9.78443	24-HR	7TH	0.16521	9.61922	9.78443
494806	4196791	9.97889	24-HR	7TH	0.29251	9.68637	9.97889
494806	4197185	9.72732	24-HR	7TH	0.37966	9.34766	9.72732
494968.8	4197480	9.47717	24-HR	7TH	0.34296	9.13422	9.47717
495050.2	4197480	9.58123	24-HR	7TH	0.34942	9.23181	9.58123
495100	4197500	9.64369	24-HR	7TH	0.36465	9.27905	9.64369
495131.6	4197480	9.68378	24-HR	7TH	0.40811	9.27567	9.68378
495200	4197600	9.57868	24-HR	7TH	0.39306	9.18562	9.57868
495221.2	4197567	9.6557	24-HR	7TH	0.33942	9.31628	9.6557
495221.3	4197657	9.45133	24-HR	7TH	0.20935	9.24198	9.45133
495221.3	4197746	9.24447	24-HR	7TH	0.41403	8.83044	9.24447
494100	4196500	9.85009	24-HR	7TH	0.12443	9.72565	9.85009
495100	4197600	9.48336	24-HR	7TH	0.35005	9.1333	9.48336
495200	4197500	9.69765	24-HR	7TH	0.34733	9.35032	9.69765
495200	4197700	9.27572	24-HR	7TH	0.2124	9.06332	9.27572
495213	4197480	9.68258	24-HR	7TH	0.33691	9.34567	9.68258
495221.2	4197478	9.68239	24-HR	7TH	0.33596	9.34643	9.68239
494100	4196600	9.38665	24-HR	8TH	0.14904	9.23762	9.38665
494200	4196400	9.24431	24-HR	8TH	0.23006	9.01425	9.24431
494200	4196500	9.6087	24-HR	8TH	0.28767	9.32103	9.6087
494200	4196600	9.54866	24-HR	8TH	0.39091	9.15775	9.54866
494200	4196700	9.50424	24-HR	8TH	0.24515	9.25909	9.50424
494200	4196800	9.5045	24-HR	8TH	0.33693	9.16757	9.5045
494300	4196400	9.33925	24-HR	8TH	0.25194	9.08732	9.33925
494300	4196500	9.57864	24-HR	8TH	0.25739	9.32126	9.57864
494300	4196600	9.65704	24-HR	8TH	0.39798	9.25906	9.65704
494300	4196700	9.51417	24-HR	8TH	0.16052	9.35365	9.51417
494300	4196800	9.64561	24-HR	8TH	0.36879	9.27681	9.64561
494300	4196900	9.74546	24-HR	8TH	0.26897	9.47649	9.74546
494400	4196400	9.33125	24-HR	8TH	0.25954	9.07171	9.33125
494400	4196500	9.4994	24-HR	8TH	0.19882	9.30058	9.4994
494400	4196600	9.65069	24-HR	8TH	0.33676	9.31393	9.65069
494400	4196700	9.50863	24-HR	8TH	0.31525	9.19338	9.50863
494400	4196800	9.64602	24-HR	8TH	0.32649	9.31953	9.64602
494400	4196900	9.89184	24-HR	8TH	0.34195	9.54989	9.89184
494400	4197000	9.57962	24-HR	8TH	0.52004	9.05958	9.57962
494500	4196400	9.27678	24-HR	8TH	0.10827	9.16851	9.27678

494500	4196500	9.51527	24-HR	8TH	0.2035	9.31177	9.51527
494500	4196600	9.63248	24-HR	8TH	0.38165	9.25083	9.63248
494500	4196700	9.57331	24-HR	8TH	0.48104	9.09227	9.57331
494500	4196800	9.61292	24-HR	8TH	0.50264	9.11028	9.61292
494500	4196900	9.87823	24-HR	8TH	0.31123	9.56701	9.87823
494500	4197000	9.69401	24-HR	8TH	0.60911	9.0849	9.69401
494600	4196400	9.20974	24-HR	8TH	0.12236	9.08738	9.20974
494600	4196500	9.27531	24-HR	8TH	0.22598	9.04933	9.27531
494600	4196600	9.43635	24-HR	8TH	0.37025	9.0661	9.43635
494600	4196700	9.53228	24-HR	8TH	0.35224	9.18004	9.53228
494600	4196800	9.59335	24-HR	8TH	0.53245	9.0609	9.59335
494600	4196900	9.82537	24-HR	8TH	0.29465	9.53072	9.82537
494600	4197000	9.66197	24-HR	8TH	0.50433	9.15765	9.66197
494600	4197100	9.63903	24-HR	8TH	0.60272	9.03631	9.63903
494700	4196500	9.21608	24-HR	8TH	0.1217	9.09438	9.21608
494700	4196600	9.17015	24-HR	8TH	0.2367	8.93344	9.17015
494700	4196700	9.42226	24-HR	8TH	0.27119	9.15107	9.42226
494700	4196800	9.5518	24-HR	8TH	0.2131	9.3387	9.5518
494700	4196900	9.71807	24-HR	8TH	0.31933	9.39874	9.71807
494700	4197000	9.54475	24-HR	8TH	0.50281	9.04195	9.54475
494700	4197100	9.53257	24-HR	8TH	0.50478	9.02778	9.53257
494800	4196700	9.27226	24-HR	8TH	0.2492	9.02306	9.27226
494800	4196800	9.4497	24-HR	8TH	0.24454	9.20516	9.4497
494800	4197200	9.38818	24-HR	8TH	0.32451	9.06366	9.38818
494806	4196693	9.25467	24-HR	8TH	0.24504	9.00963	9.25467
494806	4196791	9.46521	24-HR	8TH	0.33476	9.13045	9.46521
494806	4197185	9.39034	24-HR	8TH	0.26041	9.12993	9.39034
494968.8	4197480	9.08798	24-HR	8TH	0.21429	8.87368	9.08798
495050.2	4197480	9.16163	24-HR	8TH	0.61314	8.54849	9.16163
495100	4197500	9.18768	24-HR	8TH	0.60798	8.5797	9.18768
495131.6	4197480	9.3004	24-HR	8TH	0.5291	8.7713	9.3004
495200	4197600	9.1192	24-HR	8TH	0.54704	8.57216	9.1192
495221.2	4197567	9.10384	24-HR	8TH	0.53621	8.56763	9.10384
495221.3	4197657	9.10523	24-HR	8TH	0.39413	8.71111	9.10523
495221.3	4197746	8.98747	24-HR	8TH	0	0	0
494100	4196500	9.45024	24-HR	8TH	0.37031	9.07993	9.45024
495100	4197600	8.93848	24-HR	8TH	0	0	0

495200	4197500	9.24407	24-HR	8TH	0.62608	8.61799	9.24407	
495200	4197700	9.00777	24-HR	8TH	0.32236	8.68541	9.00777	
495213	4197480	9.36108	24-HR	8TH	0.57547	8.78561	9.36108	
495221.2	4197478	9.37689	24-HR	8TH	0.57619	8.8007	9.37689	
494100	4196600	9.05581	24-HR	9TH	0.14964	8.90617	9.05581	
494200	4196400	9.11606	24-HR	9TH	0.09906	9.01701	9.11606	
494200	4196500	9.05766	24-HR	9TH	0.14215	8.91551	9.05766	
494200	4196600	9.22068	24-HR	9TH	0.24862	8.97206	9.22068	
494200	4196700	9.22887	24-HR	9TH	0.4076	8.82127	9.22887	
494200	4196800	9.26204	24-HR	9TH	0.16584	9.09621	9.26204	
494300	4196400	9.12052	24-HR	9TH	0.09977	9.02075	9.12052	
494300	4196500	9.13087	24-HR	9TH	0.09634	9.03454	9.13087	
494300	4196600	9.35597	24-HR	9TH	0.31649	9.03948	9.35597	
494300	4196700	9.24908	24-HR	9TH	0.42823	8.82085	9.24908	
494300	4196800	9.29729	24-HR	9TH	0.25047	9.04682	9.29729	
494300	4196900	9.22763	24-HR	9TH	0.40573	8.8219	9.22763	
494400	4196400	9.10119	24-HR	9TH	0.04858	9.05261	9.10119	
494400	4196500	9.19666	24-HR	9TH	0.12476	9.07189	9.19666	
494400	4196600	9.3851	24-HR	9TH	0.33137	9.05373	9.3851	
494400	4196700	9.32728	24-HR	9TH	0.48875	8.83853	9.32728	
494400	4196800	9.33901	24-HR	9TH	0.34127	8.99774	9.33901	
494400	4196900	9.24467	24-HR	9TH	0.44111	8.80356	9.24467	
494400	4197000	9.0879	24-HR	9TH	0.47613	8.61178	9.0879	
494500	4196400	8.98976	24-HR	9TH	0	0	0	
494500	4196500	9.02611	24-HR	9TH	0.20683	8.81928	9.02611	
494500	4196600	9.28027	24-HR	9TH	0.14145	9.13881	9.28027	
494500	4196700	9.31253	24-HR	9TH	0.46757	8.84495	9.31253	
494500	4196800	9.38218	24-HR	9TH	0.21704	9.16514	9.38218	
494500	4196900	9.24906	24-HR	9TH	0.46433	8.78473	9.24906	
494500	4197000	9.15694	24-HR	9TH	0.55027	8.60667	9.15694	
494600	4196400	9.01647	24-HR	9TH	0.21469	8.80178	9.01647	
494600	4196500	8.93339	24-HR	9TH	0	0	0	
494600	4196600	9.11408	24-HR	9TH	0.10309	9.01099	9.11408	
494600	4196700	9.25319	24-HR	9TH	0.17422	9.07897	9.25319	
494600	4196800	9.34155	24-HR	9TH	0.19907	9.14248	9.34155	
494600	4196900	9.2274	24-HR	9TH	0.53163	8.69576	9.2274	
494600	4197000	9.14592	24-HR	9TH	0.71861	8.42731	9.14592	Max IG Train

494600	4197100	9.01034	24-HR	9TH	0.45764	8.5527	9.01034
494700	4196500	8.84137	24-HR	9TH	0	0	0
494700	4196600	8.96122	24-HR	9TH	0	0	0
494700	4196700	9.04424	24-HR	9TH	0.1733	8.87093	9.04424
494700	4196800	9.39168	24-HR	9TH	0.40392	8.98775	9.39168
494700	4196900	9.15361	24-HR	9TH	0.4937	8.6599	9.15361
494700	4197000	9.08972	24-HR	9TH	0.49206	8.59766	9.08972
494700	4197100	9.02879	24-HR	9TH	0.51597	8.51282	9.02879
494800	4196700	8.97784	24-HR	9TH	0	0	0
494800	4196800	9.36126	24-HR	9TH	0.37798	8.98328	9.36126
494800	4197200	9.12969	24-HR	9TH	0.43789	8.6918	9.12969
494806	4196693	8.96685	24-HR	9TH	0	0	0
494806	4196791	9.34626	24-HR	9TH	0.32833	9.01793	9.34626
494806	4197185	9.11681	24-HR	9TH	0.43634	8.68047	9.11681
494968.8	4197480	8.89488	24-HR	9TH	0	0	0
495050.2	4197480	8.96009	24-HR	9TH	0	0	0
495100	4197500	8.8661	24-HR	9TH	0	0	0
495131.6	4197480	8.91792	24-HR	9TH	0	0	0
495200	4197600	8.79675	24-HR	9TH	0	0	0
495221.2	4197567	8.79006	24-HR	9TH	0	0	0
495221.3	4197657	8.84541	24-HR	9TH	0	0	0
495221.3	4197746	8.90953	24-HR	9TH	0	0	0
494100	4196500	9.06109	24-HR	9TH	0.1084	8.95269	9.06109
495100	4197600	8.79419	24-HR	9TH	0	0	0
495200	4197500	8.8702	24-HR	9TH	0	0	0
495200	4197700	8.85449	24-HR	9TH	0	0	0
495213	4197480	8.95453	24-HR	9TH	0	0	0
495221.2	4197478	8.96797	24-HR	9TH	0	0	0
494100	4196600	8.93835	24-HR	10TH	0	0	0
494200	4196400	8.82526	24-HR	10TH	0	0	0
494200	4196500	8.78616	24-HR	10TH	0	0	0
494200	4196600	8.86301	24-HR	10TH	0	0	0
494200	4196700	8.9248	24-HR	10TH	0	0	0
494200	4196800	8.87182	24-HR	10TH	0	0	0
494300	4196400	8.83202	24-HR	10TH	0	0	0
494300	4196500	8.84339	24-HR	10TH	0	0	0
494300	4196600	8.85288	24-HR	10TH	0	0	0

494300	4196700	9.09783	24-HR	10TH	0.50513	8.5927	9.09783
494300	4196800	8.71207	24-HR	10TH	0	0	0
494300	4196900	8.79649	24-HR	10TH	0	0	0
494400	4196400	8.93484	24-HR	10TH	0	0	0
494400	4196500	8.95303	24-HR	10TH	0	0	0
494400	4196600	8.90602	24-HR	10TH	0	0	0
494400	4196700	9.12199	24-HR	10TH	0.44007	8.68193	9.12199
494400	4196800	8.74361	24-HR	10TH	0	0	0
494400	4196900	8.76628	24-HR	10TH	0	0	0
494400	4197000	8.81366	24-HR	10TH	0	0	0
494500	4196400	8.90723	24-HR	10TH	0	0	0
494500	4196500	8.8991	24-HR	10TH	0	0	0
494500	4196600	8.99276	24-HR	10TH	0	0	0
494500	4196700	9.10459	24-HR	10TH	0.36349	8.7411	9.10459
494500	4196800	8.95969	24-HR	10TH	0	0	0
494500	4196900	8.79919	24-HR	10TH	0	0	0
494500	4197000	8.73742	24-HR	10TH	0	0	0
494600	4196400	8.81135	24-HR	10TH	0	0	0
494600	4196500	8.79965	24-HR	10TH	0	0	0
494600	4196600	8.93031	24-HR	10TH	0	0	0
494600	4196700	8.94705	24-HR	10TH	0	0	0
494600	4196800	9.13698	24-HR	10TH	0.34677	8.79021	9.13698
494600	4196900	8.85144	24-HR	10TH	0	0	0
494600	4197000	8.79957	24-HR	10TH	0	0	0
494600	4197100	8.821	24-HR	10TH	0	0	0
494700	4196500	8.66093	24-HR	10TH	0	0	0
494700	4196600	8.72645	24-HR	10TH	0	0	0
494700	4196700	8.8313	24-HR	10TH	0	0	0
494700	4196800	9.14283	24-HR	10TH	0.32717	8.81566	9.14283
494700	4196900	8.93072	24-HR	10TH	0	0	0
494700	4197000	8.96362	24-HR	10TH	0	0	0
494700	4197100	8.89092	24-HR	10TH	0	0	0
494800	4196700	8.75604	24-HR	10TH	0	0	0
494800	4196800	9.18903	24-HR	10TH	0.22265	8.96639	9.18903
494800	4197200	8.84708	24-HR	10TH	0	0	0
494806	4196693	8.73065	24-HR	10TH	0	0	0
494806	4196791	9.20066	24-HR	10TH	0.22341	8.97725	9.20066

494806	4197185	8.85816	24-HR	10TH	0	0	0
494968.8	4197480	8.46707	24-HR	10TH	0	0	0
495050.2	4197480	8.7137	24-HR	10TH	0	0	0
495100	4197500	8.75247	24-HR	10TH	0	0	0
495131.6	4197480	8.77238	24-HR	10TH	0	0	0
495200	4197600	8.45121	24-HR	10TH	0	0	0
495221.2	4197567	8.47924	24-HR	10TH	0	0	0
495221.3	4197657	8.55094	24-HR	10TH	0	0	0
495221.3	4197746	8.67517	24-HR	10TH	0	0	0
494100	4196500	8.76554	24-HR	10TH	0	0	0
495100	4197600	8.50371	24-HR	10TH	0	0	0
495200	4197500	8.71003	24-HR	10TH	0	0	0
495200	4197700	8.61417	24-HR	10TH	0	0	0
495213	4197480	8.7081	24-HR	10TH	0	0	0
495221.2	4197478	8.70346	24-HR	10TH	0	0	0
494100	4196600	8.67895	24-HR	11TH	0	0	0
494200	4196400	8.57993	24-HR	11TH	0	0	0
494200	4196500	8.52417	24-HR	11TH	0	0	0
494200	4196600	8.64245	24-HR	11TH	0	0	0
494200	4196700	8.71926	24-HR	11TH	0	0	0
494200	4196800	8.42038	24-HR	11TH	0	0	0
494300	4196400	8.68101	24-HR	11TH	0	0	0
494300	4196500	8.63028	24-HR	11TH	0	0	0
494300	4196600	8.62082	24-HR	11TH	0	0	0
494300	4196700	8.66221	24-HR	11TH	0	0	0
494300	4196800	8.54336	24-HR	11TH	0	0	0
494300	4196900	8.34131	24-HR	11TH	0	0	0
494400	4196400	8.76766	24-HR	11TH	0	0	0
494400	4196500	8.62596	24-HR	11TH	0	0	0
494400	4196600	8.61943	24-HR	11TH	0	0	0
494400	4196700	8.76276	24-HR	11TH	0	0	0
494400	4196800	8.58292	24-HR	11TH	0	0	0
494400	4196900	8.35901	24-HR	11TH	0	0	0
494400	4197000	8.31313	24-HR	11TH	0	0	0
494500	4196400	8.72011	24-HR	11TH	0	0	0
494500	4196500	8.60426	24-HR	11TH	0	0	0
494500	4196600	8.56596	24-HR	11TH	0	0	0

494500	4196700	8.81677	24-HR	11TH	0	0	0
494500	4196800	8.65264	24-HR	11TH	0	0	0
494500	4196900	8.5192	24-HR	11TH	0	0	0
494500	4197000	8.37254	24-HR	11TH	0	0	0
494600	4196400	8.58049	24-HR	11TH	0	0	0
494600	4196500	8.54629	24-HR	11TH	0	0	0
494600	4196600	8.48527	24-HR	11TH	0	0	0
494600	4196700	8.79091	24-HR	11TH	0	0	0
494600	4196800	8.74828	24-HR	11TH	0	0	0
494600	4196900	8.69867	24-HR	11TH	0	0	0
494600	4197000	8.46931	24-HR	11TH	0	0	0
494600	4197100	8.18421	24-HR	11TH	0	0	0
494700	4196500	8.4179	24-HR	11TH	0	0	0
494700	4196600	8.52652	24-HR	11TH	0	0	0
494700	4196700	8.76991	24-HR	11TH	0	0	0
494700	4196800	8.75347	24-HR	11TH	0	0	0
494700	4196900	8.81855	24-HR	11TH	0	0	0
494700	4197000	8.52139	24-HR	11TH	0	0	0
494700	4197100	8.34491	24-HR	11TH	0	0	0
494800	4196700	8.65895	24-HR	11TH	0	0	0
494800	4196800	8.69947	24-HR	11TH	0	0	0
494800	4197200	8.40308	24-HR	11TH	0	0	0
494806	4196693	8.60108	24-HR	11TH	0	0	0
494806	4196791	8.71311	24-HR	11TH	0	0	0
494806	4197185	8.42523	24-HR	11TH	0	0	0
494968.8	4197480	8.24248	24-HR	11TH	0	0	0
495050.2	4197480	8.36795	24-HR	11TH	0	0	0
495100	4197500	8.48109	24-HR	11TH	0	0	0
495131.6	4197480	8.49111	24-HR	11TH	0	0	0
495200	4197600	8.33568	24-HR	11TH	0	0	0
495221.2	4197567	8.41789	24-HR	11TH	0	0	0
495221.3	4197657	8.30612	24-HR	11TH	0	0	0
495221.3	4197746	8.3422	24-HR	11TH	0	0	0
494100	4196500	8.52916	24-HR	11TH	0	0	0
495100	4197600	8.35273	24-HR	11TH	0	0	0
495200	4197500	8.47736	24-HR	11TH	0	0	0
495200	4197700	8.38329	24-HR	11TH	0	0	0

495213	4197480	8.48245	24-HR	11TH	0	0	0
495221.2	4197478	8.49396	24-HR	11TH	0	0	0

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a PSD/Part 70 Operating Permit: Appendix D: Compliance Assurance Monitoring (CAM) Plan

Source Background and Description

Source Name:	**Indiana Gasification LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

INTRODUCTION

This Compliance Assurance Monitoring (CAM) Plan has been developed for the following two emissions sources at the Indiana Gasification Facility.

- The Regenerative Thermal Oxidizer (RTO) on the Acid Gas Removal (AGR) System (CO); and
- The Wet Sulfuric Acid (WSA) Plant (NO_x, H_2SO_4 & SO_2)

These sources are subject to the Compliance Assurance Monitoring (CAM) Rule (40 CFR 64) because they meet the following three criteria for applicability per 40 CFR 64.2:

(1) Are subject to an emission limitation or standard,
(2) Use a control device to achieve compliance with an emission limitation or standard, and
(3) Have the potential to emit pre-control device emissions equal to or greater than 100% of the amount to be classified as a major source.

This CAM regulation establishes criteria that define the monitoring, reporting, and recordkeeping that must be conducted by regulated emission sources to demonstrate continuous compliance with emission limitations and standards for applicable sources.

CAM PLAN for Regenerative Thermal Oxidizer for AGR system

Background on Affected Emission Units

Emission Units

Cooled syngas, produced by gasifying coal and/or petcoke, is sent to the AGR system that utilizes a Rectisol process to remove primarily H_2S and COS. The AGR system, which will have two Rectisol trains, will have two resultant intermediate process streams (cleaned syngas and acid gas) and one waste off-gas stream. While the waste off-gas stream will primarily contain CO_2, potential pre-control device emissions of Carbon Monoxide (CO) will be greater than 100 tons per year, the major source threshold. Two natural gas-fired Regenerative Thermal Oxidizers (RTOs) that share a common stack will be used to abate emissions of CO from the Acid Gas Removal (AGR) system (IDEM Emissions Unit ID 07).

Applicable Regulations

Indiana State regulation 326 IAC 2-2-3 requires an analysis of Best Available Control Technology (BACT) to determine an appropriate limitation for the emissions of PSD-applicable pollutants from a new major source. As an emission limit, BACT for this emission unit is defined as 65 pounds of CO emissions per hour at the RTO exhaust. CO emissions are controlled to this level through the design of the RTOs, which are proposed as BACT.

Control Devices

A regenerative thermal oxidizer is an abatement device that converts CO from process gas streams into CO_2 using high temperature thermal oxidation and a system to recover a portion of the sensible heat prior to venting the exhaust gases to the atmosphere to improve energy efficiency.

Description of Monitoring Procedures

The parameters to be monitored are as follows:

(a) Combustion chamber temperature

(b) Annual burner inspection

Combustion Chamber Temperature

The combustion chamber temperature from the RTOs will be monitored continuously with a thermocouple located at the outlet of the combustion chamber. Temperature data will be recorded continuously (i.e. once every 15 minutes).

Annual Burner Inspection

The RTO burner will be inspected at least once per calendar year (minimum). The following information will be noted on a log form.

- Emission Unit ID
- Observer’s Name
- Date and Time
- Burner Condition
- Adjustments performed, if any

Emission Unit Performance Criteria

The performance criteria for the emission unit in terms of allowable ranges for the monitored parameters, corrective action time periods, maximum number of discrepancies and data availability are summarized below:

Performance Range for Monitored Criteria

1. *Combustion Chamber Temperature.* The established performance range for the RTO shall be a recommended minimum temperature from the manufacturer, 1600°F, or from the design or operating engineers. This minimum temperature may be determined and/or confirmed during the shakedown period of the initial plant start up.

2. *Annual Burner Inspection.* The RTO burners will be inspected once per calendar year.

Corrective Action Periods

Corrective Action will be initiated according to the following schedule:

Corrective action will be initiated as soon as practically possible using controlled shutdown procedures. The deficiency will be rectified before operation of the unit resumes.

Maximum Number of Excursions

1. *Combustion Chamber Temperature*. The maximum number of allowed excursions below the recommended combustion chamber temperature in any reporting period from the RTO unit is five (5).

2. *Annual Burner Inspection*. No excursions are allowed.

Data Availability

The minimum data availability for each semi-annual reporting period, defined as the number of days for which monitoring data are available divided by the number of days during which the process operated (times 100), will be 90 percent.

Quality Control Procedures

The quality control procedures to be implemented as part of the monitoring plan are described below:

Combustion Chamber Temperature

The RTO thermocouple will be inspected and calibrated at least quarterly to ensure the thermocouple is functioning properly. Additionally, since thermocouples must be replaced once they fail (e.g. thermocouple can not be readjusted), at least one spare thermocouple will be maintained onsite.

Annual Burner Inspection

The burner will be inspected and adjusted, if needed, annually to ensure proper operation.

Recordkeeping and Reporting

Monitoring Report

A semi-annual monitoring report will be submitted to the Indiana Department of Environmental Management (IDEM). The report will include the following:

1. Dates and times of any exceedance;
2. The corrective action taken for each reported discrepancy, including the time corrective action was initiated, the time corrective action was completed, and a description of the corrective action.

Site Record Retention

The following information will be retained at the site:

1. Continuous (i.e. every 15 minutes) combustion chamber temperature and annual inspection logs.

Quality Improvement Plan Implementation

A Quality Improvement Plan (QIP) will be initiated if the following thresholds are exceeded:

A. More than 5 excursions of minimum combustion chamber temperature are recorded in a 6-month period (from all units addressed under this Plan).

If the QIP threshold is exceeded, a QIP will be developed and implemented as expeditiously as possible and shall notify IDEM if QIP development will require more than 180 days.

Justification for Monitoring Measurements

The design of thermal oxidation systems is dependent on pollutant concentration, type of pollutant, oxygen concentration, waste gas stream flow rate and the degree of control required. Important design factors include temperature high enough to ignite the pollutant, turbulence or mixing or the combustion air and waste gas and sufficient residence time to allow for the combustion reaction to occur. Of these, only temperature and oxygen concentration can be sufficiently controlled after design and construction of the oxidation system.

The oxygen concentration will be controlled by the excess air flow rate to the burner and annual burner inspection will ensure a proper fuel to air mixture. Temperature of combustion systems can be accurately monitored with thermocouples or a variety of other devices. Thermocouples are highly reliable, relative low cost, widely used, require very little maintenance, and when functioning appropriately, very accurate (± 1 to 2%).

Selection of Performance (Trigger) Levels

1. *Combustion Chamber Temperature*. Minimum combustion chamber temperature.
2. *Annual Burner Inspection.* Once per calendar year inspection and adjustment, if needed, of the RTO burner.

CAM PLAN for Wet Sulfuric Acid Plant

Background on Affected Emission Units

Emission Units

The emission unit that is being incorporated into this plan is the WSA Plant (IDEM Emission Unit ID 15) which has potential pre-control device emissions of NOx, SO_2, and H_2SO_4 greater than 100 tons per year, the major source threshold.

Applicable Regulations

Indiana State regulation 326 IAC 2-2-3 requires an analysis of Best Available Control Technology (BACT) to determine an appropriate limitation for the emissions of PSD-applicable pollutants from a new major source. As an emission limit, BACT for this emission unit is proposed equivalent to 0.15 pounds of H_2SO_4 emissions and 0.25 pounds SO_2 per ton of acid produced and 10.7 pounds of NO_x per hour from each of the two processing trains. SO_2 and H_2SO_4 mist emissions will be controlled to this level through the design of the WSA unit (which includes high efficiency drift eliminators) and by using a Hydrogen Peroxide Scrubber, which is proposed as BACT. Similarly, NOx will be controlled to this level by employing Selective Catalytic Reduction (SCR) technology, which is proposed as BACT.

Control Devices

A hydrogen peroxide scrubber is a wet scrubber that uses hydrogen peroxide in solution as a scrubbing medium. Sulfur containing compounds (SO_2/H_2SO_4) in the inlet gas stream are absorbed by the hydrogen peroxide.

SCR is a catalyst system. A reducing agent, in this case anhydrous ammonia, is injected into the exhaust upstream of the catalyst bed to enhance conversion of NOx into diatomic nitrogen, N_2 and water.

Description of Monitoring Procedures

The parameters to be monitored are as follows:

(a) Hydrogen Peroxide flow rate (to the hydrogen peroxide scrubber)

(b) NOx emission rate (in the final exhaust stack).

Hydrogen Peroxide Flow Rate

The Hydrogen Peroxide flow rate from the hydrogen peroxide scrubber will be recorded with a flow meter once per operating day (minimum). The following information will be noted on a log form.

- Emission Unit ID
- Observer's Name
- Date and Time
- Flow rate

NOx Emission Rate

The NOx emission rate in the final exhaust stack will be directly measured by a continuous emission monitor (CEM).

Emission Unit Performance Criteria

The performance criteria for the emission unit in terms of allowable ranges for the monitored parameters, corrective action time periods, maximum number of discrepancies and data availability are summarized below:

Performance Range for Monitored Criteria

1. *Hydrogen Peroxide Flow Rate.* The established performance range for the hydrogen peroxide scrubber shall be a recommended flow rate of hydrogen peroxide from the manufacturer, or from the design or operating engineers. The minimum flow rate may be established during the shakedown period during initial plant performance test.

2. *NOx Emission Rate.* The NOx emission rate shall not exceed 10.7 pounds per hour from each processing train.

Corrective Action Periods

Corrective Action will be initiated according to the following schedule:

Corrective action will be initiated as soon as practically possible using controlled shutdown procedures. The deficiency will be rectified before operation of the unit resumes.

Maximum Number of Excursions

1. *Hydrogen Peroxide Flow Rate*. The maximum number of allowed excursions below the recommended flow rate in any reporting period from the hydrogen peroxide scrubber is five (5).

2. *NOx Emission Rate*. No excursions above the NOx emission limit are allowed.

Data Availability

For the hydrogen peroxide scrubber flow rate measurements, the minimum data availability for each semi-annual reporting period, defined as the number of days for which monitoring data are available divided by the number of days during which the process operated (times 100), will be 90 percent.

Except for system breakdowns, repairs, calibration checks and zero and span adjustments, the NOx CEMs shall be in continuous operation when the process is operating. The NOx CEMs shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period (except as noted above).

Quality Control Procedures

The quality control procedures to be implemented as part of the monitoring plan are described below:

Hydrogen Peroxide Flow Rate

The hydrogen peroxide scrubber’s flow rate will be monitored to achieve the highest removal efficiency for the unit. The flow meter will be inspected and calibrated at least quarterly to ensure the device is functioning properly.

NOx CEMs

Although no NSPS applies to this unit, IG proposes to follow the quality control requirements of 40 CFR Part 60 Subpart A, 40 CFR Part 60 Appendix B performance specifications 2 and 6, and 40 CFR Part 60 Appendix F for the NOx CEMs.

Recordkeeping and Reporting

Monitoring Report

A semi-annual monitoring report will be submitted to the Indiana Department of Environmental Management (IDEM). The report will include the following:

1. Dates and times of any exceedance;
2. The corrective action taken for each reported discrepancy, including the time corrective action was initiated, the time corrective action was completed, and a description of the corrective action.

Site Record Retention

The following information will be retained at the site:

1. Daily flow rate check logs for the hydrogen peroxide flow rate
2. For each NOx CEM: Records of daily zero and span drift calibrations, dates and descriptions of repairs, and CEM readings.

Quality Improvement Plan Implementation

A Quality Improvement Plan (QIP) will be initiated if the following thresholds are exceeded:

A. More than 5 excursions of flow rate are recorded in a 6-month period.

B. More than 1 excursion of the NOx emission rate in a 6-month period.

If the QIP threshold is exceeded, a QIP will be developed and implemented as expeditiously as possible and shall notify IDEM if QIP development will require more than 180 days.

Justification for Monitoring Measurements

The hydrogen peroxide scrubber removes SO_2 and H_2SO_4 from an inlet gas stream. A higher hydrogen peroxide flow rate is important in achieving the highest removal efficiency.

CEMs directly measure emission rates and provide the most accurate indication of control device performance.

Selection of Performance (Trigger) Levels

1 *Hydrogen Peroxide Flow Rate.* Minimum flow rate.

2. *NOx Emission Rate.* Maximum emission rate.

Indiana Department of Environmental Management
Office of Air Quality

Appendix E

Source Background and Description

Source Name:	**Indiana Gasification, LLC**
Source Location:	**CR 200 N and Base Road, Rockport, IN 47635**
County:	**Spencer**
SIC Code:	**4925, 2819**
Operation Permit No.:	**T 147-30464-00060**
Operation Permit Issuance Date:	**Yet to be Issued**
Permit Reviewer:	**Josiah Balogun**

Indiana Gasification Project
SCR Cost Effectiveness Determination for Auxilary Boiler

Boiler size	816	MMBtu/hr (may be two half size boilers with common stack)
Max. Operating Hours	1752	hours/yr
Boiler NOx with LNB/FGR	0.0125	lb NOx/mmbtu
Boiler NOx with LNB/FGR	8.9352	tons/yr NOx
Boiler NOx with SCR	0.0069	lb NOx/mmbtu
Boiler NOx with SCR	4.964	tons/yr NOx
Emissions reduction from SCR	3.971	tons/yr NOx

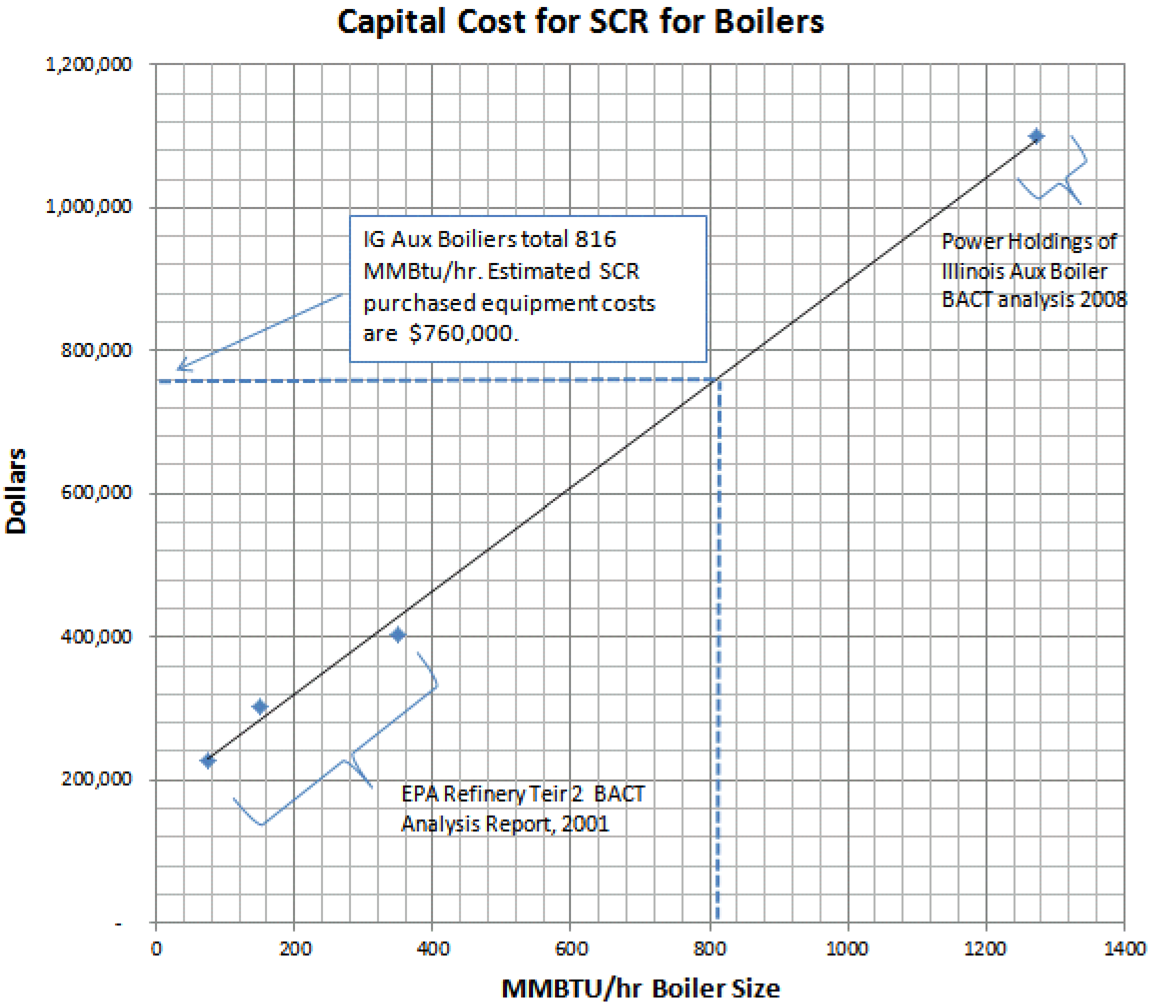
Description of Costs		**Costs**	**Source**
Capital Costs			
Direct Capital Costs (DC)			
Purchased Equipment Costs (PE)			
A. Basic Equipment Costs		$760,000	Note 1.
B. Auxiliary Equipment (0.1A)		$76,000	OAQPS
C. Instrumentation (0.1A)		$76,000	OAQPS
	PE =	$912,000	
Direct Installation Costs (DI)			
A. Foundation and Supports (0.08 PE)		$72,960	OAQPS
B. Handling and Erection (0.14 PE)		$127,680	OAQPS
C. Electrical (0.04 PE)		$36,480	OAQPS
D. Insulation (0.01 PE)		$9,120	OAQPS
E. Piping (0.02 PE)		$18,240	OAQPS
F. Painting (0.01 PE)		$9,120	OAQPS
	DI =	$273,600	
	Direct Capital Costs (DC) =	$1,185,600	
Indirect Costs (IC)			
A. Engineering/ Supervision (0.1 PE)		$91,200	OAQPS
B. Contractor Fees (0.1 PE)		$91,200	OAQPS
C. Construction/Field (0.05 PE)		$45,600	OAQPS
D. Contingencies (0.03 PE)		$27,360	OAQPS
E. Startup (0.02 PE)		$18,240	OAQPS
F. Performance Testing (0.01 PE)		$9,120	OAQPS
	Indirect Costs (IC) =	$282,720	
Total Capital Costs (TC)	**Total Capital Costs (TC) =**	$1,468,320	

Indiana Gasification Project
SCR Cost Effectiveness Determination for Auxilary Boiler
(Continued from Previous Page)

Annualized Costs

Direct Annual Costs (DA)			
	Operator/Supervision (ignored for this analysis)		
	Maintenance (ignored for this analysis)		
	Ammonia (ignored for this analysis)		
	Fuel Penalty (ignored for this analysis)		
	Catalyst Replacement (assume 0.75 * PE(A) / 10 years)	$57,000	URS Estim.
	Catalyst Disposal (ignored for this analysis)		
Indirect Annual Costs (IA)			
	Overhead (ignored for this analysis)		
	Property Tax (0.01 TC)	$14,683	OAQPS
	Insurance (0.01 TC)	$14,683	OAQPS
	Administration (0.02 TC)	$29,366	OAQPS
	Capital Recovery (0.14 TC) Interest rate 7%, period 10 yr.	$205,565	OAQPS
	Total Annualized Costs (TA) =	**$321,298**	
	NOx controlled with SCR (tons/yr)	**3.97**	**tons/yr**
	Cost Effectiveness ($/ton controlled)	**$80,907**	**$/ton**

Note 1. Purchased SCR equipment cost is based on interprelation of data for multiple sizes of heaters presented in US EPA 2001 Petroleum Refinery Tier 2 BACT Analysis Report which showed heaters up to 350 MMBtu/hr, and the purchased cost estimate from Power Holdings 2008 Permit Application SCR cost effectiveness for their 1294 MMBtu/hr Aux. Boiler. (Note: capital costs for SCR per MMBTU/hr between EPA and Power Holdings showed general agreement.)

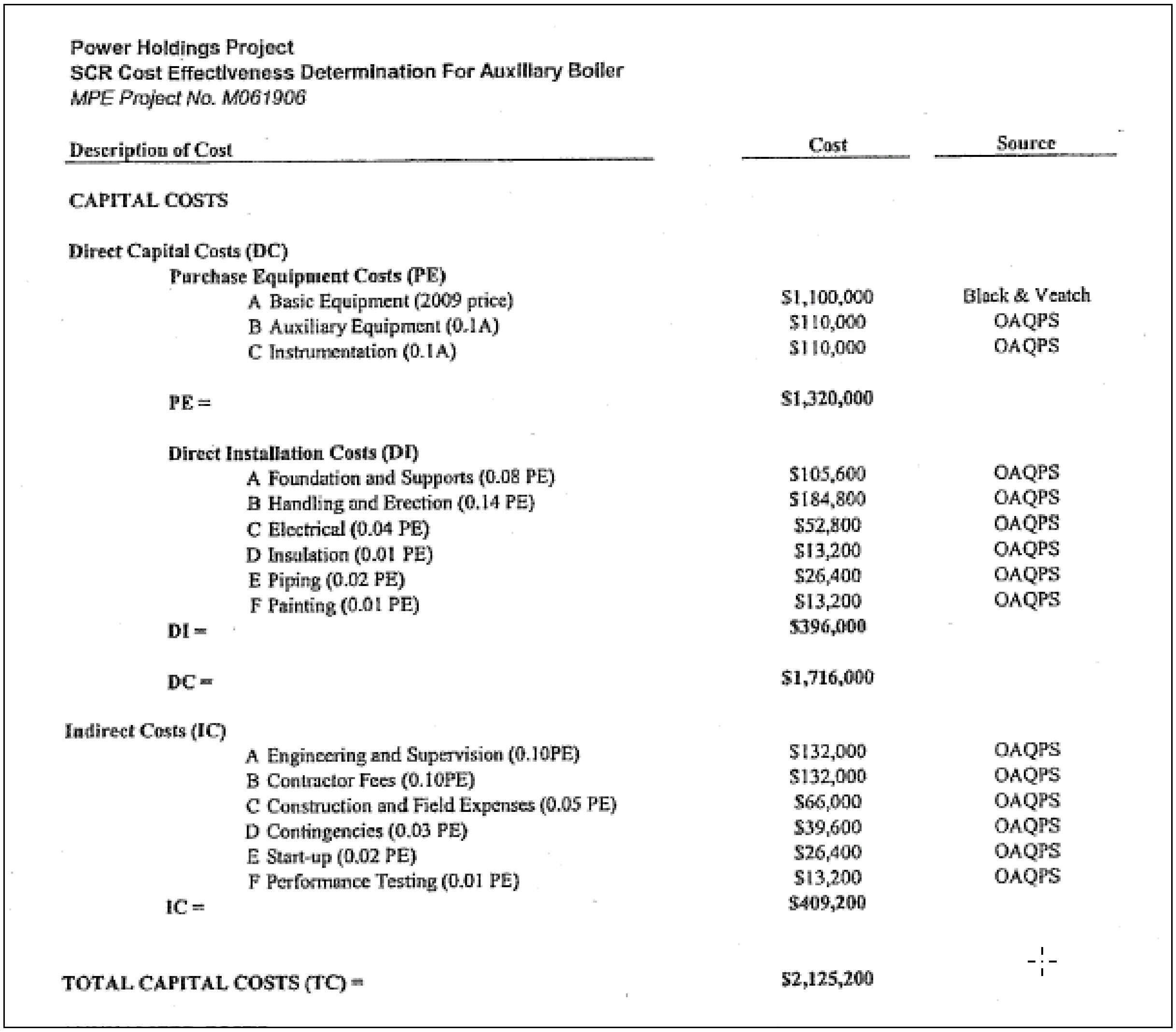


Information Sources:

SCR costs for modest size heaters obtained from US EPA *Petroleum Refinery Tier 2 BACT Analysis Report – Final Report* at http://epa.gov/ttncaaa1/t1/memoranda/bactrpt.pdf

$1.1 Million Purchased equipment cost estimate from Power Holdings BACT analysis of their Auxiliary Boiler is shown on the next page of this Appendix.

Excerpt from Power Holdings of Ilinios Auxiliary Boiler BACT Analysis – Application page 4-25
(Shows estimate of Purchased Equipment Costs (PE) for SCR for 1294 MMBtu/hr Boiler. Information used on graph on previous page in this Appendix.)



Power Holdings Project
SCR Cost Effectiveness Determination For Auxiliary Boiler
MPE Project No. M061906

Description of Cost	Cost	Source
CAPITAL COSTS		
Direct Capital Costs (DC)		
Purchase Equipment Costs (PE)		
A Basic Equipment (2009 price)	$1,100,000	Black & Veatch
B Auxiliary Equipment (0.1A)	$110,000	OAQPS
C Instrumentation (0.1A)	$110,000	OAQPS
PE =	**$1,320,000**	
Direct Installation Costs (DI)		
A Foundation and Supports (0.08 PE)	$105,600	OAQPS
B Handling and Erection (0.14 PE)	$184,800	OAQPS
C Electrical (0.04 PE)	$52,800	OAQPS
D Insulation (0.01 PE)	$13,200	OAQPS
E Piping (0.02 PE)	$26,400	OAQPS
F Painting (0.01 PE)	$13,200	OAQPS
DI =	**$396,000**	
DC =	**$1,716,000**	
Indirect Costs (IC)		
A Engineering and Supervision (0.10PE)	$132,000	OAQPS
B Contractor Fees (0.10PE)	$132,000	OAQPS
C Construction and Field Expenses (0.05 PE)	$66,000	OAQPS
D Contingencies (0.03 PE)	$39,600	OAQPS
E Start-up (0.02 PE)	$26,400	OAQPS
F Performance Testing (0.01 PE)	$13,200	OAQPS
IC =	**$409,200**	
TOTAL CAPITAL COSTS (TC) =	**$2,125,200**	

Costs of LDAR Programs

Costs of Implementing LDAR Program

Source: Petroleum Refinery Tier 2 BACT Analysis Report - Final Report, US EPA, Jan. 16, 2001

EPA Example Costs VOC control with NESHAPS LDAR program (MACT Subpart CC) for various example process Units.

	(A)	*(B)*	*(C)*	*(D)*	*(E)*	*(F)*
Example Process Units in Report	Total Components/ unit	Annualized Program Costs	Annual VOC tons/yr saved	Annual Product Value taken as Credit in annualized costs	Annualized LDAR costs w/o product value	Approx. Annual LDAR program $/component
	Note 1	*Note 2*	*Note 2*	*Note 3*	*(B+D)*	*(E/A)*
Large Refinery Hydrotreater	3566	$27,321	120	$11,703	$39,024	$11
Small Refinery Hydrotreater	1771	$10,086	70	$6,827	$16,913	$10
Large Refinery H2U	1056	$11,312	125	$12,191	$23,503	$22
Small Refinery H2U	614	$6,470	68	$6,632	$13,102	$21
					Average	**$16**

Component counts include valve, connectors, pumps, etc.

Source of above data is US EPA report "Petroleum Refinery Tier 2 BACT Analysis Report - Final Report, US EPA, Jan. 16, 2001
http://epa.gov/ttncaaa1/t1/memoranda/bactrpt.pdf

Note 1 Components for each example in EPA report shown in Appendix B, Table B-1A and B-1B.

Note 2 Annualized LDAR costs and annual VOC savings (tons/yr) shown in Table 4-3 on page 4-13.

Note 3 Annualized cost in Note 2 (Table 4-3) is reduced by credit taken for value of process fluid ($215/Mg) discussed on Page 4-14.

Costs of a NESHAPS LDAR Program for IG Process Streams

Process Streams	IG Number of Components	Pollutant	Uncontrolled Emissions tons/yr	LDAR Controlled tons/yr	IG Estimated LDAR Costs per year (Note 1)	LDAR Cost-Effectiveness $/ton	Pollutant Controlled
Acid Gas Components	88	H2SO4	0.085	0.003	$1,408	$17,005	H2SO4

Note 1. LDAR program costs assumed to be $16/yr/component per US EPA 2001 Refinery Tier 2 BACT report (see separate summary). Costs do not include separate extra cost for purchase/maintenance of unique monitor that would be needed for non-hydrocarbon monitoring (FID not responsive to non-hydrocarbons)

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Mark Lubbers
Indiana Gasification LLC
PO Box 55934
Indianapolis, IN 46205

DATE: June 27, 2012

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

SUBJECT: Final Decision
Title V
147-30464-00060

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
James Hauck (Attorney Hatchett & Hauck)
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
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(317) 232-8603
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June 27, 2012

TO: Spencer County Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Indiana Gasification LLC
Permit Number: 147-30464-00060

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 11/30/07

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Governor

Thomas W. Easterly
Commissioner

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

TO: Interested Parties / Applicant

DATE: June 27, 2012

RE: Indiana Gasification LLC / 147-30464-00060

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

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

If you would like to request a paper copy of the permit document, please contact IDEM's central file room at:

Indiana Government Center North, Room 1201
100 North Senate Avenue, MC 50-07
Indianapolis, IN 46204
Phone: 1-800-451-6027 (ext. 4-0965)
Fax (317) 232-8659

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

Mail Code 61-53

IDEM Staff	CDENNY 6/26/2012 Indiana Gasification LLC 147-30464 -00060(final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Mark Lubbers Indiana Gasification LLC PO Box 55934 Indianapolis IN 46205 (Source CAATS)									
2		Thomas Mara President Indiana Gasification LLC 315 Park Ave South, 20th Floor New York NY 10010-3607 *(RO CAATS)*									
3		Mr. Wendell Hibdon Plumbers & Steam Fitters Union, Local 136 2300 St. Joe Industrial Park Dr Evansville IN 47720 *(Affected Party)*									
4		Ms. Francis Lueken 223 W. 10th Street, P.O. Box 206 Ferdinand IN 47532 *(Affected Party)*									
5		Mr. Wayne Werne 10185 E SR 62 Ferdinand IN 47532 *(Affected Party)*									
6		Ms. Donna R. Martin 1524 S Old State Road 45 Rockport IN 47635 *(Affected Party)*									
7		Rockport City Council and Mayors Office P.O. Box 151 Rockport IN 47635 *(Local Official)*									
8		Spencer Co Public Library 210 N Walnut St Rockport IN 47635-1398 *(Library)*									
9		Mr. Thomas Utter Lincolnland Economical Development Corporation PO Box 400 Santa Claus IN 47579 *(Affected Party)*									
10		Ms. Kathy Tretter Dubois-Spencer Counties Publishing Co, Inc P.O. Box 38 Ferdinand IN 47532-0038 *(Affected Party)*									
11		Mr. Rex Winchell 715 W. Old SR 45 Rockport IN 47635 *(Affected Party)*									
12		Mr. Larry E. Sigler 668 East C.R. 700 North Chrisney IN 47611-9315 *(Affected Party)*									
13		Spencer County Commissioners 200 Main St., Courthouse Rockport IN 47635 (Local Official)									
14		Spencer County Health Department Main Street Courthouse, 1st Floor, Room 1 Roackport IN 47635-1492 *(Health Department)*									
15		Mr. Mark Wilson Evansville Courier & Press P.O. Box 268 Evansville IN 47702-0268 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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1		James M. Hauck Hatchett & Hauck 111 Monument Circle Suite 301 Indianapolis IN 46204 (Attorney) (PICKED UP IN PERSON)									
2		Mr. John Blair 800 Adams Ave Evansville IN 47713 *(Affected Party)*									
3		Eager Development PO Box 1612 Owensboro KY 42302 *(Affected Party)*									
4		Lincolnland Ecanomic Development PO Box 276 Rockport IN 47635 *(Affected Party)*									
5		Indiana Michigan Power Company P.O. Box 16428 Columbus OH 43216 *(Affected Party)*									
6		Mason & Don Foertsch P.O. Box 16 Lamar IN 47500 *(Affected Party)*									
7		Jasper Properties, LLC PO Box 162 Jasper IN 47547 *(Affected Party)*									
8		Kingdom Hall of Jehovahs Witnesses 1038 N. SR 66 Rockport IN 47635 *(Affected Party)*									
9		Gregory & Mary James 1062 N. SR 66 Rockport IN 47635 *(Affected Party)*									
10		Trustees of The Apostolic Bible Church 713 Jefferson Rockport IN 47635 *(Affected Party)*									
11		Sylvester W & Agnes R Dilger Revocatble Trust 676 N Meadowland Dr Rockport IN 47635 *(Affected Party)*									
12		Hurm Farms Inc 371 E CR 200 N Rockport IN 47635 *(Affected Party)*									
13		Miramonte Property Mgmt LLC PO Box 10 Hebron OH 43025-0010 (Affected Party)									
14		Michael D & Wanda L Toler 93 E CR 200 N Rockport IN 47635 *(Affected Party)*									
15		Commonwealth Aluminum Concast 25825 Science Park Dr, Ste 400 Beachwood OH 44122-7392 *(Affected Party)*									

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1		Nancy Shelton & Leona Matthews 418 S Lincoln Ave Rockport IN 47635 (Affected Party)									
2		Raymond & Patricia L Dawson 319 E CR 250 N Rockport IN 47635 *(Affected Party)*									
3		Owen C & Katherine Robinson 419 E CR 250 N Rockport IN 47635 *(Affected Party)*									
4		State of Indiana 3650 S US Hwy 41 Vincennes IN 47759 *(Affected Party)*									
5		Crown Communications Inc 4017 Washington Rd McMurray PA 15317 *(Affected Party)*									
6		Coal Inland Inc 1111 Western Row Rd Mason OH 45040 *(Affected Party)*									
7		Reo Properties LLC PO Box 27 Handerson KY 42419 *(Affected Party)*									
8		Rainbow Development Corp 4100 N Silverdale Rd Rockport IN 47635 *(Affected Party)*									
9		Landmark Bible Church 1124 N SR 66 Rockport IN 47635 *(Affected Party)*									
10		Mulzer Crushed Stone PO Box 249 Tell City IN 47586 *(Affected Party)*									
11		Bernard J Jr. & Mary Martha Hurm 2862 N Old State Rd Rockport IN 47635 *(Affected Party)*									
12		Sidney R Lindsey Life Estate 217 Main St Rockport IN 47635 *(Affected Party)*									
13		Spencer County Sand LLC PO Box 2428 Clarksville IN 47131 (Affected Party)									
14		Norfolk Southern Railroad 1200 Peachtree St, Box 7-142 Atlanta GA 30309-3579 *(Affected Party)*									
15		Kathryn Williams & Laurel Montgomery 1837 Towington Dr Raliegh NC 27615 *(Affected Party)*									

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											Remarks
1		C Wayne Mastin, Sharon Greene & Darlene Richey 2611 S CR 350 W Rockport IN 47635 (Affected Party)									
2		Ms. April Tuley/Gray 602 S CR 200 N Rockport IN 47635 *(Affected Party)*									
3		Larry J & Melina S Hurm 1848 N CR 200 W Rockport IN 47635 *(Affected Party)*									
4		Richard Family LLC 788 W SR 66 Rockport IN 46735 *(Affected Party)*									
5		Dan & Jessee Rininger 1001 N Silverdale Rd Rockport IN 47635 *(Affected Party)*									
6		Gilbert H Hartig Life Estate 7824 Middle Mt Vernon Rd Evansville IN 47712 *(Affected Party)*									
7		Harlan Lehr 1441 N Base Rd Rockport IN 47635 *(Affected Party)*									
8		Cleon Hurm 4127 W Eureka Rd Rockport IN 47635 *(Affected Party)*									
9		Mr. Roger Hurm 3610 N Silverdale Rd Rockport IN 47635 *(Affected Party)*									
10		Mr. Donald Schroeder 2281 W CR 350 S Rockport IN 46735 *(Affected Party)*									
11		Michael & Janice Cochenour 349 E CR 350 N Rockport IN 47635 *(Affected Party)*									
12		Paul Schulte 4100 Silverdale Rd. Rockport IN 47635 *(Affected Party)*									
13		Town Council and Town of Grandview 316 Main St. Grandview IN 47615 (Affected Party)									
14		Quinn Bowden 1100 W 42nd St # 218 Indianapolis IN 46208 *(Affected Party)*									
15		Rock Blanchard 6539 W CR 400 N Richland City IN 47634 *(Affected Party)*									

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1		Angela PO Box 213 Santa Claus IN 47579 (Affected Party)									
2		Marvin Byrer 2166 E Tennessee Evansville IN 47711 *(Affected Party)*									
3		James Lacy Kamuf 117 E 18th St PMB #125 Owensboro KY 42301 *(Affected Party)*									
4		Mickey Toler 1617 N CR 312 W Rockport IN 47635 *(Affected Party)*									
5		Harold Goffinet 426 Main St Rockport IN 47635 *(Affected Party)*									
6		Alton Goodwin 2368 N Silverdale Rd Rockport IN 47635 *(Affected Party)*									
7		Ferman Yearby 313 Elm St Rockport IN 47635 *(Affected Party)*									
8		Chuck Botsko 12540 N Base Rd Gentryville IN 47537 *(Affected Party)*									
9		Jean Dolezal 8401 E SR 70 Evanston IN 47531 *(Affected Party)*									
10		N Ryan Zaricki 1001 Oliver Rd N Wadesville IN 47638 *(Affected Party)*									
11		Wallace McMullen 12907 Sunnybrook Dr Prospect KY 40059 *(Affected Party)*									
12		Ben Taylor 419 Yel-G-View Rd Maceo KY 42355 *(Affected Party)*									
13		Thomas Pearce 223 E Ornsby Ave Louisville KY 40203 (Affected Party)									
14		William Rosenberg 508 Queensferry Rd Gary NC 27511 *(Affected Party)*									
15		Joseph Begle 2340 E CR 1600 N Lincoln City IN 47552 *(Affected Party)*									

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1		Mark 11329 E SR 32 Zionsville IN 46077 (Affected Party)									
2		Vicki Johnson 101 N 9th St Rockport IN 47635 *(Affected Party)*									
3		David Weber 6752 N 250 W Chrisney IN 47611 *(Affected Party)*									
4		Steve McNamara 332 S Second Rockport IN 47635 *(Affected Party)*									
5		Leslie Wiggins 5313 Old Boonville Hwy Evansville IN 47715 *(Affected Party)*									
6		Mark Osborne 5055 Jamestown Dr Newburgh IN 47630 *(Affected Party)*									
7		Becky Haaff 5341 W CR 200 S Rockport IN 47635 *(Affected Party)*									
8		Brandon Ferguson 1124 Ravenswood Dr Evansville IN 47714 *(Affected Party)*									
9		Tom Garrett 5313 Old Booneville Hwy Evansville IN 47715 *(Affected Party)*									
10		Beth Macke 4713 Housebridge Rd Corydon KY 42406 *(Affected Party)*									
11		Jim Werner 2646 N Burkhardt Rd Evansville IN 47715 *(Affected Party)*									
12		James Hunsicker 11686 US 231 S Dale IN 47523 *(Affected Party)*									
13		Paul Morsey 2437 Pleasant Valley Rd Owensboro KY 42303 (Affected Party)									
14		William Bailey 841 South Rockport IN 47635 *(Affected Party)*									
15		Agnes Dilger 676 N Meadowland Dr Rockport IN 47635 *(Affected Party)*									

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1		John 6830 Roosevelt Ave Franklin OH 45005 (Affected Party)									
2		David Boggs 216 Western Hills Dr Mt Vernon IN 47620 *(Affected Party)*									
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