



## INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

*We Protect Hoosiers and Our Environment.*

100 N. Senate Avenue • Indianapolis, IN 46204

(800) 451-6027 • (317) 232-8603 • [www.idem.IN.gov](http://www.idem.IN.gov)

**Michael R. Pence**  
Governor

**Thomas W. Easterly**  
Commissioner

To: Interested Parties

Date: June 4, 2014

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

Source Name: Midwest Fertilizer Corporation

Permit Level: PSD/New Source Construction and Title V Operating Permit

Permit Number: 129-33576-00059

Source Location: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana

Type of Action Taken: Initial Permit

### **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 matter referenced above.

The final decision is available on the IDEM website at: <http://www.in.gov/apps/idem/caats/>  
To view the document, select Search option 3, then enter permit 33576.

If you would like to request a paper copy of the permit document, please contact IDEM's central file room:

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

Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

*(continues on next page)*

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 impracticable 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.



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Commissioner

## PSD/New Source Construction and Part 70 Operating Permit


### OFFICE OF AIR QUALITY

**Midwest Fertilizer Corporation  
Intersection Old SR 69 and Mackey Ferry Road East  
Mt. Vernon, Indiana 47620**

(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.: T129-33576-00059	
Issued by:  Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: June 4, 2014 Expiration Date: June 4, 2019



A State that Works

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#### ***Construction Conditions***

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##### **Effective Date of the Permit**

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

#### ***Operating Conditions***

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

- D.2.4 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]
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##### **Effective Date of the Permit**

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**Effective Date of the Permit**

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***Operating Conditions***

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

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**General Construction Conditions**

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**Effective Date of the Permit**

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

D.7.4 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

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***Construction Conditions***

**General Construction Conditions**

- D.8.1 Permit No Defense

**Effective Date of the Permit**

- D.8.2 Effective Date of the Permit [IC 13-15-5-3]
- D.8.3 Modification to Construction Conditions [326 IAC 2]

***Operating Conditions***

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

- D.8.4 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

**Compliance Determination Requirements**

- D.8.5 Compliance Determination Requirements

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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)]

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The Permittee owns and operates a stationary nitrogen fertilizer manufacturing facility.

Source Address:	Intersection Old SR 69 and Mackey Ferry Road East Mt. Vernon, Indiana 47620
General Source Phone Number:	(317) 625-8315
SIC Code:	2873
County Location:	Posey
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)]

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

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.
  - (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.
- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.
- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.
- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.



- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]
- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.
- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]
- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively. [40 CFR 60, Subpart KKKK]
- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]
- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1. [40 CFR 60, Subpart VVa]
- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.
- (l) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-21A.
- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

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

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

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]
- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]

- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]
- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]
- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]
- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]
- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tank does not contain an organic liquid. [326 IAC 2-2]
- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]
- (bb) Two (2) ammonia storage tanks, identified as EU-032 and EU-033, approved for construction in 2014, each with a maximum capacity of 30,000 metric tons, using Ammonia Storage Flare EU-016 for emissions control, exhausting to stack S-016. The tanks do not contain an organic liquid. [326 IAC 2-2]

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

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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).

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

## B.2 Revocation of Permits [326 IAC 2-2-8]

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

- (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)]

## B.5 Term of Conditions [326 IAC 2-1.1-9.5]

- (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]**

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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)]**

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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)]**

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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)]**

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- (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)]**

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- (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(35), 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(35).

**B.11 Annual Compliance Certification [326 IAC 2-7-6(5)]**

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- (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(35).

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

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- (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(35).

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(35).
- (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]**

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- (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 Southwest Regional Office within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality,  
Compliance and Enforcement Branch), or  
Telephone Number: 317-233-0178 (ask for Office of Air Quality,  
Compliance and Enforcement Branch)  
Facsimile Number: 317-233-6865  
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304.

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

Indiana Department of Environmental Management  
Compliance 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(35).

- (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]**

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

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

- (b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.
- (c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.
- (d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:
  - (1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;
  - (2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;
  - (3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and
  - (4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.
- (e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

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

**B.15 Prior Permits Superseded [326 IAC 2-1.1-9.5] [326 IAC 2-7-10.5]**

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- (a) All terms and conditions of permits established prior to T129-33576-00059 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.

**B.16 Termination of Right to Operate [326 IAC 2-7-10] [326 IAC 2-7-4(a)]**

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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]**

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- (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(35).
- (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)]**

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- (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(42). 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(35).

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]**

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- (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) 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(35).

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

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- (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]**

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- (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)(1) and (c)(1). 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(37)) 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(35).

- (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.

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**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.

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**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]**

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- (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(35).

- (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]**

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- (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]**

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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 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 by using ambient air quality modeling pursuant to 326 IAC 1-7-4. 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.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]**

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The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140. The requirement in 326 IAC 14-10-1(a) that the owner or operator shall use an Indiana Licensed Asbestos Inspector and all the requirements 326 IAC 18 related to licensing requirements for asbestos inspectors are not federally enforceable.

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

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

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- (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(35).

- (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(35).
- (c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

**Compliance Requirements [326 IAC 2-1.1-11]**

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

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

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

**C.10 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)] [40 CFR 64] [326 IAC 3-8]**

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- (a) For new units:  
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

- (b) For existing units:  
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 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, 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(35).

- (c) 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.
- (d) 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.

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C.11 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. The analog instrument shall be capable of measuring values outside of the normal range.
- (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.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]**

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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 one hundred eighty (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(35).
- (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.13 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]**

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

### **C.14 Response to Excursions or Exceedances [40 CFR 64] [326 IAC 3-8] [326 IAC 2-7-5] [326 IAC 2-7-6]**

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- (l) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, 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 64.8b(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.15 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5]  
[326 IAC 2-7-6]

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- (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(35).

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

C.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)] [326 IAC 2-7-5(7)] [326 IAC 2-7-19(c)]  
[326 IAC 2-6]

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In accordance with the compliance schedule specified in 326 IAC 2-6-3(b)(3), starting in 2018 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(35).

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

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- (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, where applicable:

- (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, where applicable:

- (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(o) and/or 326 IAC 2-3-1(j)) 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(o) and/or 326 IAC 2-3-1(j)) 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 (as defined in 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(yy)) 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.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3] [40 CFR 64] [326 IAC 3-8]

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- (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(35). 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 (oo) and/or 326 IAC 2-3-1 (jj)) 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 (ww) and/or 326 IAC 2-3-1 (pp), 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.19 Compliance with 40 CFR 82 and 326 IAC 22-1**

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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.0 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

#### Entire Source

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

### Definitions

#### D.0.1 Definitions

The terms used in this Part 70 Operating Permit shall have the meanings set forth in the underlying rule or subpart and in this section, whichever is more restrictive, as follows:

- (a) Natural gas-fired means an emission unit fueled by pipeline natural gas.
- (b) Pipeline natural gas has the meaning outlined in 40 CFR 72.2. Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geologic formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot.

## SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.
- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.
- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively. [40 CFR 60, Subpart KKKK]
- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]**

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Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) shall be as follows:

(a) **Reformer Furnace (EU-001)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:

#### **General Conditions**

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the operation of the reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (2) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;

#### **PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (3) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the operation of the reformer furnace (EU-001) shall not exceed 1.9, 5.385, and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;

#### **NO<sub>x</sub>**

- (4) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
- (5) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range;

#### **CO**

- (6) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average;

#### **VOC**

- (7) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average;

### **GHGs**

- (8) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
- (9) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet stream flows;
- (10) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
- (11) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.

### **SSM Events for NO<sub>x</sub>**

- (12) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:
  - (a) **Startup:**

Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its "minimum safe stable load" which is defined as that operating condition when:

    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
    - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
  - (b) **Shutdown:**

Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.
  - (c) **Malfunction:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

(b) **Startup Heater (EU-002)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the startup heater (EU-002) shall be as follows:

**General Conditions**

- (1) The startup heater (EU-002) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (3) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month;

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (4) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;

**NO<sub>x</sub>**

- (5) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average;

**CO**

- (6) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average;

**VOC**

- (7) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and

**GHGs**

- (8) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

(c) **Open-Simple Cycle Combustion Turbines (EU-013A and EU-013B)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the open-simple cycle combustion turbines (EU-013A/B) shall be as follows:

### **General Conditions**

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design and good combustion practices at all times the units are in operation;
- (2) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;

### **PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (3) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0019 lb/MMBtu, based on a three-hour average;
- (4) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average;

### **NO<sub>x</sub>**

- (5) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of dry low NO<sub>x</sub> combustors;
- (6) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average;

### **CO**

- (7) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average;

### **VOC**

- (8) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average;

### **GHGs**

- (9) Thermal efficiency of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) emissions shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and



- (11) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.

(d) **Auxiliary Boilers (EU-012A, EU-012B and EU-012C)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be as follows:

**General Conditions**

- (1) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC, and GHG emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (3) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (4) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (5) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;

**NO<sub>x</sub>**

- (6) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (7) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average;

**CO**

- (8) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average;

### **VOC**

- (9) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average;

### **GHGs**

- (10) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- (11) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
- (12) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

#### **D.1.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A][326 IAC 12-1]**

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- (a) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the natural gas-fired, open-simple cycle combustion turbines (EU-013A and EU-013B) except when otherwise specified in 40 CFR 60, Subpart KKKK.
- (b) The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the natural gas-fired auxiliary boilers (EU-012A, EU-012B, and EU-012C) except when otherwise specified in 40 CFR 60, Subpart Db

#### **D.1.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart KKKK] [326 IAC 12]**

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The Permittee shall comply with the following provisions of 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) included as Attachment C of this permit, which was incorporated by reference as 326 IAC 12, for the natural gas-fired, open-simple cycle combustion turbines (EU-013A and EU-013B) as specified as follows:

- (1) 40 CFR 60.4300;
- (2) 40 CFR 60.4305;
- (3) 40 CFR 60.4315;
- (4) 40 CFR 60.4320(a);
- (5) 40 CFR 60.4330(a)(2);
- (6) 40 CFR 60.4333;
- (7) 40 CFR 60.4335(b);
- (8) 40 CFR 60.4345;
- (9) 40 CFR 60.4350(f)(2) and (h);
- (10) 40 CFR 60.4355;
- (11) 40 CFR 60.4365(a);
- (12) 40 CFR 60.4375(a);
- (13) 40 CFR 60.4380(b);
- (14) 40 CFR 60.4395;
- (15) 40 CFR 60.4405;
- (16) 40 CFR 60.4410; and
- (17) 40 CFR 60.4420.

**D.1.7 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Db] [326 IAC 12]**

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The Permittee shall comply with the following provisions of 40 CFR 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) included as Attachment A of this permit, which was incorporated by reference as 362 IAC 12, for the natural gas-fired auxiliary boilers (EU-012A, EU-012B, and EU-012C) as specified as follows:

- (1) 40 CFR 60.42b(k)(2);
- (2) 40 CFR 60.44b(h) and (i);
- (3) 40 CFR 60.44b(l);
- (4) 40 CFR 60.46b(a);
- (5) 40 CFR 60.46b(c);
- (6) 40 CFR 60.46b(e);
- (7) 40 CFR 60.48b(b) to (f);
- (8) 40 CFR 60.49b(a) and (b);
- (9) 40 CFR 60.49b(d);
- (10) 40 CFR 60.49b(g);
- (11) 40 CFR 60.49b(i); and
- (12) 40 CFR 60.49b(o).

**D.1.8 Preventive Maintenance Plan [326 IAC 2-7-5(12)]**

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A Preventive Maintenance Plan is required for the reformer furnace (EU-001), the natural gas-fired startup heater (EU-002), the open-simple cycle combustion turbines (EU-013A and EU-013B), and the natural gas-fired boilers (EU-012A, EU-012B, and EU-012C) and their control devices. Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

**D.1.9 HAP Minor Limit [326 IAC 2-4.1]**

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Combined hexane emissions from the reformer furnace (EU-001), the natural gas startup heater (EU-002), and the auxiliary boilers (EU-012A/B/C) shall not exceed 9.83 tons per twelve consecutive month period with compliance determined at the end of each month.

Compliance with the above limit shall ensure source-wide hexane emissions are less than ten (10) tons per twelve consecutive month period and source-wide total HAP emissions are less than twenty-five (25) tons per twelve consecutive month period and shall render the requirements of 326 IAC 2-4.1 (MACT) not applicable.

**Compliance Determination Requirements**

**D.1.10 Testing Requirements [326 IAC 2-7-6(1)] [327 IAC 2-7-6(6)]**

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**Reformer Furnace (EU-001)**

- (a) In order to demonstrate the compliance status with Condition D.1.4(a)(6) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on the reformer furnace (EU-001) stack S-001 utilizing methods as approved by the Commissioner. This is a one-time test. 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 the compliance status with Condition D.1.4(a)(8) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO<sub>2</sub> testing on the reformer furnace (EU-001) stack S-001 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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 the compliance status with Condition D.1.4(a)(10) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing on the reformer furnace (EU-001) utilizing methods as approved by the Commissioner. This is a one-time test. 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 verify the hexane emission rate (in lb/MMCF of natural gas) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform hexane testing on the reformer furnace (EU-001) stack S-001 utilizing methods as approved by the Commissioner. This is a one-time test. 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.

**Open-Simple Cycle Combustion Turbines (EU-013A and EU-013B)**

- (e) In order to demonstrate the compliance status with Condition D.1.4(c)(6), the Permittee shall perform NO<sub>x</sub> testing on the open-simple cycle combustion turbine (EU-013A/B) stacks S-013A and S-013B utilizing methods as approved by the Commissioner within one hundred and eighty (180) days after initial startup. This test shall be repeated within sixty (60) days of the entire facility reaching maximum capacity but no later than eighteen (18) months after initial startup of the turbines. This test shall then be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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.
- (f) In order to demonstrate the compliance status with Condition D.1.4(c)(7), the Permittee shall perform CO testing on the open-simple cycle combustion turbine (EU-013A/B) stacks S-013A and S-013B utilizing methods as approved by the Commissioner within one hundred and eighty (180) days after initial startup. This test shall be repeated within sixty (60) days of the entire facility reaching maximum capacity but no later than eighteen (18) months after initial startup of the turbines. 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.

- (g) In order to demonstrate the compliance status with Condition D.1.4(c)(9), the Permittee shall perform thermal efficiency testing of both combustion turbines, identified as EU-013A and EU-013B utilizing methods as approved by the Commissioner within one hundred and eighty (180) days after initial startup. This test shall be repeated within sixty (60) days of the entire facility reaching maximum capacity but no later than eighteen (18) months after initial startup of the turbines. 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.
- (h) In order to demonstrate the compliance status with Condition D.1.4(c)(10), the Permittee shall perform CO<sub>2</sub> testing on the open-simple cycle combustion turbine (EU-013A/B) stacks S-013A and S-013B utilizing methods as approved by the Commissioner within one hundred and eighty (180) days after initial startup. This test shall be repeated within sixty (60) days of the entire facility reaching maximum capacity but no later than eighteen (18) months after initial startup of the turbines. 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.

**Auxiliary Boilers (EU-012A, EU-012B and EU-012C)**

- (i) In order to demonstrate the compliance status with Condition D.1.4(d)(8) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on the auxiliary boiler (EU-012A/B/C) stacks S-012A, S-012B, and S-012C utilizing methods as approved by the Commissioner. This is a one-time test. 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.
- (j) In order to demonstrate the compliance status with Condition D.1.4(d)(10) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO<sub>2</sub> testing on the auxiliary boiler (EU-012A/B/C) stacks S-012A, S-012B, and S-012C utilizing methods as approved by the Commissioner. This is a one-time test. 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.
- (k) In order to demonstrate the compliance status with Condition D.1.4(d)(11) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform thermal efficiency testing on auxiliary boilers EU-012A, EU-012B, and EU-012C utilizing methods as approved by the Commissioner. This is a one-time test. 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.

- (l) In order to verify the hexane emission rate (in lb/MMCF of natural gas) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform hexane testing on the auxiliary boiler (EU-012A/B/C) stacks S-012A, S-012B, and S-012C utilizing methods as approved by the Commissioner. This is a one-time test. 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.1.11 Greenhouse Gas Emission Calculation [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

##### **Reformer Furnace (EU-001)**

- (a) To determine the compliance status with Condition D.1.4(a)(11), the Permittee shall use the following equation for each fuel burned to determine the CO<sub>2</sub> emissions from the Reformer Furnace (EU-001):

$$\text{CO}_2 \text{ Emissions (ton/month)} = \text{Fuel Usage (MMCF/month)} \times \text{Emission Factor (lb/MMCF)} \\ \times 1 \text{ ton} / 2,000 \text{ lb}$$

The monthly fuel emission rate for each fuel shall be summed together.

Where: Fuel Usage from fuel usage data

Emission Factor - Natural Gas = 119,220 lb CO<sub>2</sub>/MMCF

Emission Factor – Off gas = 119,220 lb CO<sub>2</sub>/MMCF x Volume % Methane

The percent volume methane in process off-gases shall be determined through measurement, process operational data, mass balance, or other engineering methods.

##### **Open-Simple Cycle Combustion Turbines (EU-013A and EU-013B)**

- (b) In order to demonstrate compliance with the emission limitation in Condition D.1.4(c)(10) for each open-simple cycle combustion turbine (EU-013A and EU-013B), the Permittee shall use the following equation:

$$\text{CO}_2 \text{ (ton/month)} = \text{Fuel Usage (MMCF/month)} \times \text{Higher Heating Value (MMBtu/MMCF)} \\ \times \text{Emission Factor (lb/MMBtu)} \times 1 \text{ ton} / 2,000 \text{ lb}$$

Where:

Fuel Usage is the amount of natural gas combusted in each turbine, each month.

Higher Heating Value is 1,020 MMBtu/MMCF, or as determined during testing.

Emission Factor is 116.89 lb/MMBtu, or as determined during testing.

#### D.1.12 Hexane Emission Calculation [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]

- (a) In order to demonstrate the compliance with Condition D.1.9, hexane emissions shall be calculated with the following equation:

Hexane Emissions (ton/month) = Hexane Emissions from Reformer Furnace EU-001 Natural Gas + Hexane Emissions from Reformer Furnace EU-001 Process Gas + Hexane Emissions Startup Heater EU-002 + Hexane Emissions from Auxiliary Boiler EU-012A + Hexane Emissions from Auxiliary Boiler EU-012B + Hexane Emissions from Auxiliary Boiler EU-012C

Where:

Hexane Emissions Reformer Furnace EU-001 Natural Gas (ton/month) =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

Hexane Emissions Reformer Furnace EU-001 Process Gas (ton/month) =  
Process Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

Hexane Emissions Startup Heater EU-002 =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012A =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012B =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012C =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or as determined by testing) x 1 ton/2,000 lb

- (b) Natural gas and process gas usage shall be determined by flow monitoring of gases sent to the combustion unit, process operational data, mass balance or other engineering methods.

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

##### **D.1.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]**

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- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO<sub>x</sub> emissions on stack S-001 for the reformer furnace (EU-001).
- (b) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO<sub>x</sub> emissions on stacks S-012A, S-012B, and S-012C for the auxiliary boilers (EU-012A/B/C).
- (c) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.
- (d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons for the breakdown and the efforts made to correct the problem.

- (e) Whenever a NO<sub>x</sub> CEMS is down for more than twenty-four (24) hours, the Permittee shall follow the best combustion practice.

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

#### **D.1.14 Record Keeping Requirements**

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- (a) In order to document the compliance status with Condition D.1.4(a)(2), the Permittee shall maintain monthly records of the type of fuel consumed in the reformer furnace (EU-001).
- (b) In order to document the compliance status with Condition D.1.4(a)(11), the Permittee shall maintain monthly records of CO<sub>2</sub> emissions from the reformer furnace (EU-001).
- (c) In order to document the compliance status with Condition D.1.9, the Permittee shall maintain monthly records of hexane emissions from the reformer furnace (EU-001), the startup heater (EU-002), and auxiliary boilers (EU-012A/B/C).
- (d) In order to document the compliance status with Condition D.1.4(b)(1), the Permittee shall maintain monthly records of the type of fuel used in the startup heater EU-002.
- (e) In order to document the compliance status with Condition D.1.4(b)(3), the Permittee shall maintain monthly records of the amount of fuel combusted in the startup heater EU-002.
- (f) In order to document the compliance status with Condition D.1.4(c)(2), the Permittee shall maintain monthly records of the type of fuel combusted in each open-simple cycle combustion turbine, identified as EU-013A and EU-013B.
- (g) In order to document the compliance status with Condition D.1.4(c)(11), the Permittee shall maintain monthly records of the amount of fuel combusted and monthly CO<sub>2</sub> emissions in each open-simple cycle combustion turbine, identified as EU-013A and EU-013B.
- (h) In order to document the compliance status with Condition D.1.4(d)(1), the Permittee shall maintain monthly records of the type of fuel combusted in each auxiliary boiler, identified as EU-012A, EU-012B, and EU-012C.
- (i) In order to document the compliance status with Condition D.1.4(d)(3), the Permittee shall maintain monthly records of the amount of fuel combusted in each auxiliary boiler, identified as EU-012A, EU-012B, and EU-012C.
- (j) In order to document compliance with Conditions D.1.4(a)(11), D.1.4(b)(3), D.1.4(c)(11), D.1.4(d)(3), D.1.9, D.1.11 and D.1.12, the Permittee shall maintain all records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine emissions or document compliance.
- (k) In order to document compliance with Conditions D.1.4(a)(5), D.1.4(d)(7), and D.1.13, the Permittee shall maintain records of the output of the continuous emission monitoring system for NO<sub>x</sub> and shall perform the required record keeping requirements of 326 IAC 3-5-6.



- (l) In order to document compliance with Condition D.1.13, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair of maintenance activities.
- (m) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### D.1.15 Reporting Requirements

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- (a) Quarterly summaries of the information to document the compliance status with Conditions D.1.4(a)(11), D.1.4(b)(3), D.1.4(c)(11), D.1.4(d)(3), and D.1.9 shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. The reports submitted by the Permittee do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined in 326 IAC 2-7-1(35).
- (b) In order to document the compliance status with Conditions D.1.4(a)(5), D.1.4(d)(7) and D.1.13, the Permittee shall comply with all of the reporting requirements pursuant to 326 IAC 3-5-7.

## SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the CO<sub>2</sub> purification process (EU-003) shall be as follows:

#### General Conditions

- (a) CO, VOC and CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;

### **CO**

- (b) CO emissions from the CO<sub>2</sub> purification process (EU-003) not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;

### **VOC**

- (c) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;

### **GHGs**

- (d) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (e) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

#### **D.2.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]**

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A Preventive Maintenance Plan is required for the purification process (EU-003). Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

### **Compliance Determination Requirements**

#### **D.2.6 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]**

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- (a) In order to demonstrate the compliance status with Condition D.2.4(b) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO testing on the CO<sub>2</sub> purification process (EU-003) stack S-003 utilizing methods as approved by the Commissioner. This is a one-time test. 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 the compliance status with Condition D.2.4(c) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform VOC testing on the CO<sub>2</sub> purification process (EU-003) stack S-003 utilizing methods as approved by the Commissioner. This is a one-time test. 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 the compliance status with Condition D.2.4(d) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform CO<sub>2</sub> testing on the CO<sub>2</sub> purification process (EU-003) stack S-003 utilizing methods as approved by the Commissioner. This is a one-time test. 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 verify the methanol emission rate (in lb/ton of ammonia produced) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform methanol testing on the CO<sub>2</sub> purification process (EU-003) stack S-003 utilizing methods as approved by the Commissioner. This is a one-time test. 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.

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

#### **D.2.7 Record Keeping Requirements**

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- (a) In order to document the compliance status with Condition D.2.4, the Permittee shall maintain monthly records of ammonia production.
- (b) In order to document the compliance status with Conditions D.2.4, the Permittee shall maintain all records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine emissions or document compliance.
- (c) In order to document the compliance status with Condition D.2.4(e), the Permittee shall maintain monthly records of the hours of venting of the CO<sub>2</sub> purification process.
- (d) In order to document the compliance status with Condition D.2.4(e), the Permittee shall maintain monthly records of CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process.
- (e) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### **D.2.8 Reporting Requirements**

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A quarterly summary of the information to document the compliance status with Condition D.2.4(e) shall be submitted using the reporting form located at the end of this permit, or its equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. 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 in 326 IAC 2-7-1(35).

## SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]
- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.
- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1. [40 CFR 60, Subpart VVa]
- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.
- (l) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-021A.
- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

### Insignificant Activity:

- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]
- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]

(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 there under, 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]

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

#### D.3.3 Modifications to Construction Conditions [326 IAC 2]

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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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

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Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) shall be as follows:

(a) **Urea Granulation Unit (EU-008)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granulator (EU-008) shall be as follows:

- (1) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall each not exceed 0.163 lb per ton granules, based on a three-hour average.

(b) **Urea Granule Storage Warehouse (EU-024)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granule storage warehouse (EU-024) shall be as follows:

- (1) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall each not exceed 0.17 lb/hr, based on a three-hour average.

(c) **Fugitive Emissions from Equipment Leaks (F-1):** Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

(d) **Truck Loading Operation (EU-020)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the truck loadout operation (EU-020) shall be as follows:

- (1) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.
- (e) **Rail Loading Operation (EU-021A)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for rail loading operation (EU-021A) shall be as follows:
- (1) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.
- (f) **Urea Junction Operation (EU-021B)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for urea junction operation (EU-021B) shall be as follows:
- (1) The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

**D.3.5 General Provisions Relating to New Source Performance Standards (NSPS)**  
[40 CFR 60, Subpart A] [326 IAC 12-1]

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The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the urea granulation unit (EU-008), the urea synthesis plant (EU-006), and the urea ammonium nitrate plant (EU-007), except when otherwise specified in 40 CFR 60, Subpart VVa.

**D.3.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart VVa] [326 IAC 12]**

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The Permittee shall comply with the following provisions of 40 CFR 60, Subpart VVa Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commences after November 7, 2006, included as Attachment D of this permit, which was incorporated by reference as 362 IAC 12, for the urea granulation unit (EU-008), fugitive emissions from equipment leaks (F-1), urea synthesis plant (EU-006), and the urea ammonium nitrate plant (EU-007), as specified as follows:

- (1) 40 CFR 60.480a(a) to (c);
- (2) 40 CFR 60.480a(d)(1) and (d)(3);
- (3) 40 CFR 60.486a(a)(1), (i), (j), and (k); and
- (4) 40 CFR 60.487a.

#### D.3.7 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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A Preventive Maintenance Plan is required for the urea granulation unit (EU-008), the urea granule storage warehouse (EU-024), the truck loading operation (EU-020), the rail loading operation (EU-021A) and the urea junction operation (EU-021B) and their control devices. Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements

#### D.3.8 Testing Requirements

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- (a) In order to demonstrate the compliance status with Condition D.3.4(a)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on the urea granulation unit (EU-008) stack S-008 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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 the compliance status with Condition D.3.4(b)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on the urea granule storage warehouse (EU-024) stack S-024 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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 the compliance status with Condition D.3.4(d)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on the truck loading operation (EU-020) stack S-020 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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 the compliance status with Condition D.3.4(e)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on the rail loading operation (EU-021A) stack S-021A utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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) In order to demonstrate the compliance status with Condition D.3.4(f)(2) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM<sub>10</sub>, and PM<sub>2.5</sub> testing on the urea junction operation (EU-021B) stack S-021B utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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.3.9 Broken or Failed Bag Detection**

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- (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 emissions unit. 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)
- (c) In the event that bag failure is observed in a multi-compartment baghouse, if the 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 the notification.

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

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

#### **D.3.10 Parametric Monitoring**

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- (a) The Permittee shall record the pressure drop across the wet scrubber used in conjunction with the urea granulation unit (EU-008), at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 4.0 and 25.0 inches of water unless a different upper-bound or lower bound value for this range is determined during the latest stack test. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take a reasonable response shall be considered a deviation from this permit.

- (b) The Permittee shall record the pressure drop across the baghouse used in conjunction with the urea granule storage warehouse (EU-024), at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower bound value for this range is determined during the latest stack test. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take a reasonable response shall be considered a deviation from this permit.
- (c) The Permittee shall record the pressure drop across the baghouse used in conjunction with the truck loading operation (EU-020), at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower bound value for this range is determined during the latest stack test. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take a reasonable response shall be considered a deviation from this permit.
- (d) The Permittee shall record the pressure drop across the baghouse used in conjunction with the rail loading operation (EU-021A), at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower bound value for this range is determined during the latest stack test. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take a reasonable response shall be considered a deviation from this permit.
- (e) The Permittee shall record the pressure drop across the baghouse used in conjunction with the urea junction operation (EU-021B), at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower bound value for this range is determined during the latest stack test. Section C – Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take a reasonable response 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 or replaced at least once every six months.

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

### **D.3.11 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.3.10(a), the Permittee shall maintain daily records of the pressure drop across the wet scrubber controlling the urea granulation unit (EU-008). 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).
- (b) To document the compliance status with Condition D.3.10(b), the Permittee shall maintain daily records of the pressure drop across the baghouse controlling the urea granule storage warehouse (EU-024). 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 Condition D.3.10(c), the Permittee shall maintain daily records of the pressure drop across the baghouse controlling the truck loading operation (EU-020). 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).
- (d) To document the compliance status with Condition D.3.10(d), the Permittee shall maintain daily records of the pressure drop across the baghouse controlling the rail loading operation (EU-021A). 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) To document the compliance status with Condition D.3.10(e), the Permittee shall maintain daily records of the pressure drop across the baghouse controlling the urea junction operation (EU-021B). 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).
- (f) 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:

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:

- (a) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton nitric acid, with the production being expressed as 100 percent nitric acid, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (b) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;

- (c) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a catalytic reactor at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (d) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, with the production being expressed as 100 percent nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (e) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> and N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:

(1) **Startup:**

Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.

(2) **Shutdown:**

Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.

(3) **Malfunctions:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

**D.4.5 General Provisions Relating to New Source Performance Standards (NSPS)**  
[40 CFR 60, Subpart A] [326 IAC 12-1]

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The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the nitric acid plant (EU-009), except when otherwise specified in 40 CFR 60, Subpart Ga.

**D.4.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Ga] [326 IAC 12]**

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The Permittee shall comply with the following provisions of 40 CFR 60, Subpart Ga (Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commences after October 14, 2011 (Included as Attachment B of this permit) which are incorporated by reference as 326 IAC 12, for the nitric acid plant, identified as EU-009 as specified as follows:

- (1) 40 CFR 60.70a;
- (2) 40 CFR 60.72a;
- (3) 40 CFR 60.73a;
- (4) 40 CFR 60.74a;
- (5) 40 CFR 60.75a;
- (6) 40 CFR 60.76a; and
- (7) 40 CFR 60.77a

**D.4.7 Preventive Maintenance Plan [326 IAC 2-7-5(12)]**

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A Preventive Maintenance Plan is required for the nitric acid plant (EU-009) and its control device. Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

**Compliance Determination Requirements**

**D.4.8 Testing Requirements**

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In order to demonstrate the compliance status with Condition D.4.4(c) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform N<sub>2</sub>O testing on the nitric acid plant (EU-009) stack S-009 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with 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.4.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5]**

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- (a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO<sub>x</sub> emissions on stack S-009.
- (b) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60, 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 for the breakdown and the efforts made to correct the problem.
- (d) Whenever a NO<sub>x</sub> CEMS is down for more than twenty-four (24) hours, the Permittee shall follow best operational practices.

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

### **D.4.10 Record Keeping Requirements**

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- (a) To document the compliance status with Condition D.4.4(a), the Permittee shall maintain monthly records of the amount of nitric acid produced in the nitric acid plant (EU-009).
- (b) To document the compliance status with Condition D.4.4(a), the Permittee shall maintain records of the 30-day average NO<sub>x</sub> emission per ton of acid produced.
- (c) To document the compliance status with Conditions D.4.4 and D.4.9, the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine emissions.
- (d) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

## SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.
- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.

### Insignificant Activity:

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) shall be as follows:



(a) **Front End Flare (EU-017)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the front end flare (EU-017) shall be as follows:

**General Conditions**

- (1) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (2) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events.
  - (A) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (5) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.

**NO<sub>x</sub>**

- (7) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.

**CO**

- (9) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, during venting, based on a three-hour average.

**VOC**

- (11) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (12) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr, during venting, based on a three-hour average.

**GHGs**

- (13) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (14) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, while venting, based on a three-hour average.

- (b) **Back End Flare (EU-018)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the back end flare (EU-018) shall be as follows:

**General Conditions**

- (1) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (2) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month;

- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (5) PM emissions from the back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

**NO<sub>x</sub>**

- (7) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.

### **CO**

- (9) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.

### **VOC**

- (11) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (12) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.

### **GHGs**

- (13) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (14) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.

(c) **Ammonia Storage Flare (EU-016)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the ammonia storage flare (EU-016) shall be as follows:

### **General Conditions**

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (2) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (5) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

**NO<sub>x</sub>**

- (7) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.

**CO**

- (9) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.

**VOC**

- (10) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.

**GHGs**

- (11) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operations, based on a three-hour average.

#### D.5.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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A Preventive Maintenance Plan is required for the front end flare (EU-017), the back end flare (EU-018), and the ammonia storage flare (EU-016). Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

### Compliance Determination Requirements

#### D.5.6 Flare Emissions [326 IAC 7-7-6(1)] [326 IAC 2-7-6(6)]

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##### Front End Flare (EU-017)

- (a) In order to demonstrate the compliance status with the emission limitations in Conditions D.5.4(a)(8), D.5.4(a)(10), D.5.4(a)(12) and D.5.4(a)(14), the Permittee shall use the following equations:

For NO<sub>x</sub>, CO, VOC, and CO<sub>2</sub>:

$$E = (H \times EF) + PE$$

Where:	E	=	Pollutant Emissions (lb/hr)
	EF <sub>NOx</sub>	=	0.0680 lb/MMBtu
	EF <sub>CO</sub>	=	0.3700 lb/MMBtu
	EF <sub>VOC</sub>	=	0.0054 lb/MMBtu
	EF <sub>CO2</sub>	=	116.8879 lb/MMBtu
	PE <sub>NOx</sub>	=	2.5660 lb/hr from pilot and purge
	PE <sub>CO</sub>	=	13.964 lb/hr from pilot and purge
	PE <sub>VOC</sub>	=	0.2040 lb/hr from pilot and purge
	PE <sub>CO2</sub>	=	4,411.47 lb/hr from pilot and purge

H = Hourly Heat Input (MMBtu/hr) = F<sub>1-4</sub> (lb/hr) x HHV x 100% (portion of flare stream combusted) x 1 MMBtu/1,000,000 Btu

Where:	F <sub>1-4</sub>	=	Flow of flared gas from ammonia free streams (lb/hr)
	HHV <sub>1</sub>	=	2,830.8 Btu/lb or other value determined by testing
	HHV <sub>2</sub>	=	2,775.0 Btu/lb or other value determined by testing
	HHV <sub>3</sub>	=	6,767.2 Btu/lb or other value determined by testing
	HHV <sub>4</sub>	=	2,830.8 Btu/lb or other value determined by testing

##### Back End Flare (EU-018)

- (b) In order to demonstrate the compliance status with the emission limitations in Conditions D.5.4(b)(8), D.5.4(b)(10), D.5.4(b)(12), and D.5.4(b)(14), the Permittee shall use the following equations:

For CO, VOC, and CO<sub>2</sub>:

$$E = (H \times EF) + PE$$

Where:	E	=	Pollutant Emissions (lb/hr)
	EF <sub>CO</sub>	=	0.3700 lb/MMBtu
	EF <sub>VOC</sub>	=	0.0054 lb/MMBtu
	EF <sub>CO2</sub>	=	116.8879 lb/MMBtu
	PE <sub>CO</sub>	=	14.158 lb/hr from pilot and purge

$$\begin{aligned} PE_{VOC} &= 0.2060 \text{ lb/hr from pilot and purge} \\ PE_{CO2} &= 4,472.60 \text{ lb/hr from pilot and purge} \end{aligned}$$

$H = \text{Hourly Heat Input (MMBtu/hr)} = F_1 \text{ (lb/hr)} \times HHV_1 \times 100\% \text{ (portion of flare stream combusted)} \times 1 \text{ MMBtu/1,000,000 Btu}$

Where:  $F_1$  = Flow of flared gas from ammonia free streams (lb/hr)  
 $HHV_1$  = 9,020.7 Btu/lb or other value determined by testing

For  $NO_x$ :

$$E = (H \times EF) + PE$$

Where:  $E$  = Pollutant Emissions (lb/hr)  
 $EF_{NOx}$  = 0.0680 lb/MMBtu  
 $PE_{NOx}$  = 2.60 lb/hr from pilot and purge

$H = \text{Hourly Heat Input (MMBtu/hr)} = F_1 \text{ (lb/hr)} \times HHV_1 \times 100\% \text{ (portion of flare stream combusted)} \times 1 \text{ MMBtu/1,000,000 Btu} + F_2 \text{ (lb/hr)} \times HHV_2 \times 98\% \text{ (portion of flare stream combusted)} \times 1 \text{ MMBtu/1,000,000 Btu}$

Where:  $F_1$  = Flow of flared gas from ammonia free streams (lb/hr)  
 $HHV_1$  = 9,020.7 Btu/lb or other value determined by testing  
 $F_2$  = Flow of flared gas from ammonia free streams (lb/hr)  
 $HHV_2$  = 7,996.5 Btu/lb or other value determined by testing

$FE_{NOx} = F \text{ (lb/hr)} \times (\text{ammonia combusted}) \times (\text{ammonia in flare gas}) \times (\text{M.W. of } NO_2 / \text{M.W. of } NH_3) \times FN\%$

Where:  $F$  = Flow of flared gases (lb/hr)  
Ammonia Combusted (98%)  
Ammonia in flare gas (99.9%)  
M.W. of  $NO_2$  = molecular weight of nitrogen dioxide = 46 lb/lb-mole  
M.W. of  $NH_3$  = molecular weight of ammonia = 17 lb/lb-mole  
FN = Fuel  $NO_x$  factor for ammonia = 0.50%

#### Ammonia Storage Flare (EU-016)

- (c) In order to demonstrate compliance with the emission limits in Conditions D.5.4(c)(8) and D.5.4(c)(11), the Permittee shall use the following equations:

For  $NO_x$  and  $CO_2$ :

$$E = (H \times EF) + PE$$

Where:  $E$  = Pollutant Emissions (lb/hr)  
 $EF_{NOx}$  = 0.0680 lb/MMBtu  
 $EF_{CO2}$  = 0 lb/MMBtu, as there are no carbon containing vent streams  
 $PE_{NOx}$  = 0.03 lb/hr from pilot and purge  
 $PE_{CO2}$  = 52.02 lb/hr from pilot and purge

$H = \text{Hourly Heat Input (MMBtu/hr)} = F \text{ (lb/hr)} \times HHV \times 100\% \text{ (portion of flare stream combusted)} \times 1 \text{ MMBtu/1,000,000 Btu}$

Where:  $F$  = Flow of flared gas from ammonia free streams (lb/hr)  
 $HHV$  = 7,779.7 Btu/lb or other value determined by testing

$FE_{NOx} = F \text{ (lb/hr)} \times (\text{ammonia combusted}) \times (\text{ammonia in flare gas}) \times (\text{M.W. of } NO_2 / \text{M.W. of } NH_3) \times FN\%$

Where:  $F$  = Flow of flared gases (lb/hr)  
Ammonia Combusted (98%)  
Ammonia in Flare Gas (98.3%)  
M.W. of  $NO_2$  = molecular weight of nitrogen dioxide = 46 lb/lb-mole  
M.W. of  $NH_3$  = molecular weight of ammonia = 17 lb/lb-mole  
 $FN$  = Fuel NOx factor for ammonia = 0.50%

- (d) The Permittee shall determine flow rates used in equations D.5.5(a), D.5.5(b) and D.5.5(c) through flow monitoring of gases sent to the flare, process operational data, mass balance, or other engineering methods.

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

#### D.5.7 Record Keeping Requirements

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- (a) In order to document the compliance status with Condition D.5.4(a)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the front end flare (EU-017).
- (b) In order to document the compliance status with Condition D.5.4(a)(2), the Permittee shall maintain a monthly records of the hours the front end flare (EU-017) vents. The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry (e.g., the process did not operate that month).
- (c) In order to document the compliance status with Condition D.5.4(b)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the back end flare (EU-018).
- (d) In order to document the compliance status with Condition D.5.4(b)(2), the Permittee shall maintain a monthly record of the hours the back end flare (EU-018) vents. The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry (e.g., the process did not operate that month).
- (e) In order to document the compliance status with Condition D.5.4(c)(1), the Permittee shall maintain monthly records of the type of fuel combusted in the ammonia storage flare (EU-016).
- (f) In order to document the compliance status with Condition D.5.4(c)(2), the Permittee shall maintain a monthly record of the hours the ammonia storage flare (EU-016) vents. The Permittee shall include in its monthly record when a venting hours entry is not recorded and the reason for a lack of a venting hours entry (e.g., the process did not operate that month).
- (g) In order to document the compliance status with Conditions D.5.4(a)(2), D.5.4(b)(2), and D.5.4(c)(2), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.



- (h) In order to document the compliance status with Condition D.5.6(a), the Permittee shall maintain monthly records of NO<sub>x</sub>, CO, VOC, CO<sub>2</sub> emissions from the front end flare (EU-017).
- (i) In order to document the compliance status with Condition D.5.6(b), the Permittee shall maintain monthly records of CO, VOC, CO<sub>2</sub> and NO<sub>x</sub> emissions from the back end flare (EU-018).
- (j) In order to document the compliance status with Condition D.5.6(c), the Permittee shall maintain monthly records of NO<sub>x</sub> and CO<sub>2</sub> emissions from the ammonia storage flare (EU-016)
- (k) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### D.5.8 Reporting Requirements

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Quarterly summaries of the information to document the compliance status with Conditions D.5.4(a)(2), D.5.4(b)(2), and D.5.4(c)(2) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. The reports submitted by the Permittee do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined in 326 IAC 2-7-1(35).

## SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

### Insignificant Activity:

- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]
- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) for the ten cell evaporative cooling tower (EU-010), and the six cell evaporative cooling tower (EU-011) shall be as follows:

- (a) **Ten Cell Evaporative Cooling Tower (EU-010)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for ten cell cooling tower (EU-010) shall be as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
  - (2) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.
- (b) **Six Cell Evaporative Cooling Tower (EU-011)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the six cell cooling tower (EU-011) shall be as follows:
- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
  - (2) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

#### D.6.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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A Preventive Maintenance Plan is required for the ten cell cooling tower (EU-010) and the six cell cooling tower (EU-011) and their control devices. Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

#### D.6.6 Parametric Monitoring

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- (a) In order to demonstrate the compliance status with Condition D.6.4(a)(2), the Permittee shall record the level of total dissolved solids in the water used in the ten cell cooling tower (EU-010) at least once per month when the cooling tower is in operation. When for any one reading, the level of total dissolved solids is above 2,000 mg/l, the Permittee shall take a reasonable response. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A single reading in excess of the above mentioned concentration 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.6.4(b)(2), the Permittee shall record the level of total dissolved solids in the water used in the six cell cooling tower (EU-011) at least once per month when the cooling tower is in operation. When for any one reading, the level of total dissolved solids is above 2,000 mg/l, the Permittee shall take a reasonable response. Section C – Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A single reading in excess of the above mentioned concentration is not 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.6.7 Record Keeping Requirements**

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- (a) In order to document the compliance status with Condition D.6.4(a)(2), the Permittee shall maintain a monthly record of the total dissolved solids concentration in the water used in the ten cell cooling tower (EU-010). The Permittee shall include in its monthly record when the total dissolved solids are not recorded and the reason for a lack of a total dissolved solids reading (e.g., the process did not operate that month).
  
- (b) In order to document the compliance status with Condition D.6.4(b)(2), the Permittee shall maintain a monthly record of the total dissolved solids concentration in the water used in the six cell cooling tower (EU-011). The Permittee shall include in its monthly record when the total dissolved solids are not recorded and the reason for a lack of a total dissolved solids reading (e.g., the process did not operate that month).

## SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

### Insignificant Activity:

- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) shall be as follows:

(a) **Distillate Oil-Fired Emergency Generator (EU-014)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency generator (EU-014) shall be as follows:

**General Conditions**

- (1) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices;

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (3) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;

**NO<sub>x</sub>**

- (4) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;

**CO**

- (5) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average;

**VOC**

- (6) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average; and

**GHGs**

- (7) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

(b) **Distillate Oil-Fired Emergency Fire Water Pump (EU-015)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency fire water pump (EU-015) shall be as follows:

**General Conditions**

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (3) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;

**NO<sub>x</sub>**

- (4) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average;

**CO**

- (5) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average;

**VOC**

- (6) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and

**GHGs**

- (7) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

(c) **Distillate Oil-Fired Emergency Raw Water Pump (EU-063)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for emergency raw water pump (EU-063) shall be as follows:

**General Conditions**

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;

**NO<sub>x</sub>**

- (4) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average;

### CO

- (5) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average;

### VOC

- (6) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and

### GHGs

- (7) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

#### D.7.5 General Provisions Relating to New Source Performance Standards (NSPS) [40 CFR 60, Subpart A] [326 IAC 12-1]

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The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the distillate oil-fired emergency generator (EU-014), the distillate oil-fired emergency fire water pump (EU-015), and the distillate oil-fired raw water pump (EU-063), except when otherwise specified in 40 CFR 60, Subpart IIII.

#### D.7.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart IIII] [326 IAC 12]

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The Permittee shall comply with the following provisions of 40 CFR 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (included as Attachment E of this permit) which are incorporated by reference as 326 IAC 12, for the distillate oil-fired emergency generator (EU-014), the distillate oil-fired emergency fire water pump (EU-015), and the distillate oil-fired raw water pump (EU-063), as specified as follows:

- (a) The emergency generator (3,600 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(i);
- (2) 40 CFR 60.4205(b);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c), and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.

- (b) The emergency fire water pump (500 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(ii);
- (2) 40 CFR 60.4205(c);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c), and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.



- (c) The emergency raw water pump (500 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(i);
- (2) 40 CFR 60.4205(b);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c) and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.

**D.7.7 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 63, Subpart A] [326 IAC 20-1]**

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Pursuant to 40 CFR 63.6665, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, as specified in Table 8 of 40 CFR 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63, Subpart ZZZZ.

**D.7.8 National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR 63, Subpart ZZZZ] [326 IAC 20-82]**

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The Permittee shall comply with the following provisions of 40 CFR 63, Subpart ZZZZ, which are incorporated by reference as 326 IAC 20-82 (Included as Attachment G of this permit), for the distillate oil-fired emergency generator (EU-014), the distillate oil-fired emergency fire water pump (EU-015), and the distillate oil-fired raw water pump (EU-063) upon startup of the affected source:

- (1) 40 CFR 63.6585(c);
- (2) 40 CFR 63.6590(a)(2)(iii);
- (3) 40 CFR 63.6590(c)(1);
- (4) 40 CFR 63.6595(a)(7);
- (5) 40 CFR 63.6670; and
- (6) 40 CFR 63.6675.

**D.7.9 Preventive Maintenance Plan [326 IAC 2-7-5(12)]**

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A Preventive Maintenance Plan is required for the distillate oil-fired emergency generator (EU-014), the distillate oil-fired emergency fire water pump (EU-015), and the distillate oil-fired raw water pump (EU-063). Section C – Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

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

**D.7.10 Record Keeping Requirements**

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- (a) In order to document the compliance status with Condition D.7.4(a)(1), the Permittee shall maintain a monthly record of the hours of operation of the diesel-fired emergency generator (EU-014).
- (b) In order to document the compliance status with Condition D.7.4(b)(2), the Permittee shall maintain a monthly record of the hours of operation of the diesel-fired emergency fire water pump (EU-015).

- (c) In order to document the compliance status with Condition D.7.4(c)(2), the Permittee shall maintain a monthly record of the hours of operation of the diesel-fired emergency raw water pump (EU-063).
- (d) Section C – General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

#### D.7.11 Reporting Requirements

Quarterly summaries of the information to document the compliance status with Conditions D.7.4(a)(1), D.7.4(b)(2), and D.7.4(c)(2) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. The reports submitted by the Permittee do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined in 326 IAC 2-7-1(35).

## SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

### Insignificant Activity:

- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]

(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 there under, 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 Modifications 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 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) for fugitive dust from paved roads and parking areas shall be as follows:

PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (a) Paving all plant haul roads;
- (b) Daily sweeping with wet suppression; and
- (c) Prompt cleanup of any spilled materials.

## Compliance Determination Requirements

### D.8.5 Compliance Determination Requirements

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To demonstrate compliance with Condition D.8.4, the Permittee shall comply with the following:

- (a) Wet Suppression for roadway dust control shall be performed on paved roads except when:
  - (1) It is raining or snowing at the time of the scheduled treatment,
  - (2) The subject portion of the haul roads is covered by ice or snow or remains wet from recent precipitation or the previous wet suppression, or
  - (3) The road is not being used as a haul road on that day.

If ambient air temperature is below 32 °F at the time of a scheduled wet suppression treatment, the Permittee may clean the roadway 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 shall be at least daily, unless a treatment is not required for a reason under (a) above, and the frequency shall be sufficient to achieve 90% control based on the following formula or an equivalent:

$$\text{Control Efficiency} = 96 - (0.263 \times (T / C))$$

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 shall be posted as 15 miles per hour or less.

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

### D.8.6 Ambient Temperature Monitoring

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To demonstrate the compliance status with Condition D.8.5, 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.8.7 Record Keeping Requirements

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To demonstrate the compliance status with Conditions D.8.4 and D.8.5, the Permittee shall maintain the following daily records for haul roads:

- (a) The number of trucks on the haul road each calendar day.
- (b) The date, approximate time, and type of each roadway dust control treatment.
- (c) If a treatment of the haul roads is not required and not performed in accordance with Condition D.8.5, records shall be maintained documenting the reason for the lack of a treatment (i.e. ambient temperature, precipitation, etc.).

## SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

### Emissions Unit Description:

#### Entire 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

#### D.9.1 General Provisions Relating to the National Emission Standards for Hazardous Air Pollutants (NESHAP) [40 CFR 61, Subpart FF] [326 IAC 14-1]

The Permittee shall comply with the provisions of 40 CFR 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1.

#### D.9.2 National Emission Standards for Hazardous Air Pollutants for Benzene Waste Operations [40 CFR 61, Subpart FF] [326 IAC 14]

The Permittee shall comply with the following provisions of 40 CFR 61, Subpart FF, which are included as Attachment F of this permit for all affected facilities upon startup of the affected source. The entire source is subject to the following portions of 40 CFR 61, Subpart FF:

- (1) 40 CFR 61.340(a) and (c);
- (2) 40 CFR 61.341;
- (3) 40 CFR 61.342(a);
- (4) 40 CFR 61.355;
- (5) 40 CFR 61.356; and
- (6) 40 CFR 61.357(a) and (b).

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

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059

**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: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059

**This form consists of 2 pages**

**Page 1 of 2**

- |  |
|--|
| <input type="checkbox"/> This is an emergency as defined in 326 IAC 2-7-1(12) <ul style="list-style-type: none"><li>• 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</li><li>• 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.</li></ul> |
|--|

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 <sub>2</sub> , VOC, NO <sub>x</sub> , 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 – Reformer Furnace CO<sub>2</sub> (EU-001)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Reformer Furnace (EU-001)  
Parameter: CO<sub>2</sub> Emissions (Condition D.1.4(a)(11))  
Limit: 486,675 tons / twelve consecutive month period with compliance determined by 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 – Startup Heater Gas Usage**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Natural gas startup heater (EU-002)  
Parameter: Natural gas usage (Condition D.1.4(b)(3))  
Limit: 18.14 MMCF/ twelve consecutive month period with compliance determined by 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 – Combustion Turbine (EU-013A) CO<sub>2</sub> Emissions**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Combustion Turbine (EU-013A)  
Parameter: CO<sub>2</sub> Emissions (Condition D.1.4(c)(11))  
Limit: 144,890 tons / twelve consecutive month period with compliance determined by 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 – Combustion Turbine (EU-013B) CO<sub>2</sub> Emissions**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Combustion Turbine (EU-013B)  
Parameter: CO<sub>2</sub> Emissions (Condition D.1.4(c)(11))  
Limit: 144,890 tons / twelve consecutive month period with compliance determined by 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 – Auxiliary Boiler Gas Usage (EU-012A)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Auxiliary Boiler (EU-012A)  
Parameter: Natural Gas Usage (Condition D.1.4(d)(3))  
Limit: 1,501.91 MMCF / twelve consecutive month period with compliance determined by 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 – Auxiliary Boiler Gas Usage (EU-012B)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Auxiliary Boiler (EU-012B)  
Parameter: Natural Gas Usage (Condition D.1.4(d)(3))  
Limit: 1,501.91 MMCF / twelve consecutive month period with compliance determined by 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 – Auxiliary Boiler Gas Usage (EU-012C)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Auxiliary Boiler (EU-012C)  
Parameter: Natural Gas Usage (Condition D.1.4(d)(3))  
Limit: 1,501.91 MMCF / twelve consecutive month period with compliance determined by 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 Wide Hexane Limit**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: reformer furnace (EU-001), startup heater (EU-002), and auxiliary boilers (EU-012A/B/C)  
Parameter: Hexane Emissions (Condition D.1.9)  
Limit: 9.83 tons / twelve consecutive month period with compliance determined by 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 – CO<sub>2</sub> Purification Process (EU-003) CO<sub>2</sub> Emissions**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: CO<sub>2</sub> Purification Process (EU-003)  
Parameter: CO<sub>2</sub> Emissions (Condition D.2.4(e))  
Limit: 1,232,475 tons / twelve consecutive month period with compliance determined by 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 – Front End Flare (EU-017)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Front End Flare (EU-017)  
Parameter: Venting Hours (Condition D.5.4(a)(2))  
Limit: 336 hours / twelve consecutive month period with compliance determined by 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 – Back End Flare Venting (EU-018)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Back End Flare (EU-018)  
Parameter: Venting Hours (Condition D.5.4(b)(2))  
Limit: 336 hours / twelve consecutive month period with compliance determined by 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 – Ammonia Storage Flare Venting (EU-016)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Ammonia Storage Flare (EU-016)  
Parameter: Venting Hours (Condition D.5.4(c)(2))  
Limit: 168 / twelve consecutive month period with compliance determined by 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 – Emergency Generator (EU-014)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Emergency Generator (EU-014)  
Parameter: Hours of Operation (Condition D.7.4(a)(1))  
Limit: 500 hours / twelve consecutive month period with compliance determined by 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 – Fire Water Pump (EU-015)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Fire Water Pump (EU-015)  
Parameter: Operating Hours (Condition D.7.4(b)(2))  
Limit: 500 hours / twelve consecutive month period with compliance determined by 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 – Raw Water Pump (EU-063)**

Source Name: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059  
Facility: Emergency Raw Water Pump (EU-063)  
Parameter: Operating Hours (Condition D.7.4(c)(2))  
Limit: 500 hours / twelve consecutive month period with compliance determined by 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: Midwest Fertilizer Corporation  
Source Address: Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620  
Part 70 Permit No.: T129-33576-00059

**Months:** \_\_\_\_\_ **to** \_\_\_\_\_ **Year:** \_\_\_\_\_

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This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C- General Reporting. 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:**



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

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

Midwest Fertilizer Corporation  
Intersection Old SR 69 and Mackey Ferry Road East  
Mt. Vernon, Indiana 47620

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 Midwest Fertilizer Corporation Intersection Old SR 69 and Mackey Ferry Road East, Mt. Vernon, Indiana 47620, completed construction of the nitrogen fertilizer manufacturing facility on \_\_\_\_\_ in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on August 26, 2013, and as permitted pursuant to New Source Construction Permit and Part 70 Operating Permit No. T129-33576-00059, Plant ID No. 129-00059 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 Department of Environmental Management Office of Air Quality

### Attachment A to a Part 70 Operating Permit

Source Description and Location	
Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 60, Subpart Db	
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**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<sub>x</sub>) 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<sub>x</sub> standards under this subpart and to the sulfur dioxide (SO<sub>2</sub>) 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<sub>x</sub> standards 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<sub>x</sub> standards under this subpart and the PM and SO<sub>2</sub> standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO<sub>x</sub> standards under this subpart and the SO<sub>2</sub> standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO<sub>x</sub> 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, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities ( *i.e.*, heat recovery steam generators) that are associated with stationary combustion 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 affected facilities ( *i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility ( *i.e.* 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 stationary combustion 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.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO<sub>2</sub> and NO<sub>x</sub> standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

## **§ 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<sub>2</sub>) 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), 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), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

*Dry flue gas desulfurization technology* means a SO<sub>2</sub> control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

*Emerging technology* means any SO<sub>2</sub> control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

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

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

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

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

*Gaseous fuel* means any fuel that is 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  $730,000 \text{ J/sec-m}^3$  ( $70,000 \text{ Btu/hr-ft}^3$ ).

*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  $730,000 \text{ J/sec-m}^3$  ( $70,000 \text{ Btu/hr-ft}^3$ ) 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  $\text{SO}_2$  emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical  $\text{SO}_2$  emissions (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.

*Temporary boiler* means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

*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<sub>2</sub> emission control, has a SO<sub>2</sub> emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 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<sub>2</sub> emission control, has a SO<sub>2</sub> emission 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<sub>2</sub> emission control, has a SO<sub>2</sub> emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

*Wet flue gas desulfurization technology* means a SO<sub>2</sub> control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO<sub>2</sub>.

*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; 77 FR 9459, Feb. 16, 2012]

**§ 60.42b Standard for sulfur dioxide (SO<sub>2</sub>).**

(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<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO<sub>2</sub> 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<sub>s</sub> = SO<sub>2</sub> emission limit, in ng/J or lb/MMBtu heat input;

K<sub>a</sub> = 520 ng/J (or 1.2 lb/MMBtu);

K<sub>b</sub> = 340 ng/J (or 0.80 lb/MMBtu);

H<sub>a</sub> = Heat input from the combustion of coal, in J (MMBtu); and

H<sub>b</sub> = 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<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO<sub>2</sub> 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<sub>2</sub> emissions, shall cause to be discharged into the atmosphere any gases that contain SO<sub>2</sub> in excess of 50 percent of the potential SO<sub>2</sub> emission rate (50 percent reduction) and that contain SO<sub>2</sub> 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<sub>s</sub> = SO<sub>2</sub> emission limit, in ng/J or lb/MM Btu heat input;

K<sub>c</sub> = 260 ng/J (or 0.60 lb/MMBtu);

K<sub>d</sub> = 170 ng/J (or 0.40 lb/MMBtu);

H<sub>c</sub> = Heat input from the combustion of coal, in J (MMBtu); and

H<sub>d</sub> = 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<sub>2</sub> in 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<sub>2</sub> emission 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<sub>2</sub> emission 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<sub>2</sub> emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO<sub>2</sub> control) 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<sub>2</sub> control system is not being operated because of malfunction or maintenance of the SO<sub>2</sub> control 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<sub>2</sub> emission 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<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO<sub>2</sub> emission 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<sub>2</sub> emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO<sub>2</sub> emissions 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<sub>2</sub> in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil 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<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO<sub>2</sub> emission 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<sub>2</sub> 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<sub>2</sub> 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 combusts 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. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is 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<sub>2</sub> or 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<sub>2</sub> 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; 77 FR 9459, Feb. 16, 2012]

#### **§ 60.44b Standard for nitrogen oxides (NO<sub>x</sub>).**

(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<sub>x</sub> (expressed as NO<sub>2</sub>) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO <sub>2</sub> ) 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	340	0.80

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO <sub>2</sub> ) heat input	
	ng/J	lb/MMBTu
Montana and combusted in a slag tap furnace		
(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 only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO<sub>x</sub> 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<sub>x</sub> emission limit (expressed as NO<sub>2</sub>), 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 (d) 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 coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO<sub>x</sub> in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with 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, natural gas (or any combination of the three).

(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 and/or distillate oil with a potential SO<sub>2</sub> emissions rate of 26 ng/J (0.060 lb/MMBTu) or less 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<sub>x</sub> in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels 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, distillate oil, or a mixture of these fuels.

(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 only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO<sub>x</sub> 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:

(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<sub>x</sub> emission 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<sub>x</sub> emissions 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<sub>x</sub> emission 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<sub>x</sub> emission 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<sub>x</sub> emission limit will be established at the NO<sub>x</sub> emission 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<sub>x</sub> emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO<sub>x</sub> limit. 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<sub>x</sub> emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO<sub>x</sub> emissions 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<sub>x</sub> emission 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<sub>x</sub> emission limits of this section. The NO<sub>x</sub> emission 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<sub>x</sub> limit. 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<sub>x</sub> standards under this section apply at all times including periods of startup, shutdown, or malfunction.

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

(j) 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<sub>x</sub> emission 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 is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO<sub>x</sub> (expressed as NO<sub>2</sub>) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with 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 any combination of the three); 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<sub>x</sub> emission limit, (lb/MMBtu);

$H_{go}$  = 30-day heat input from combustion of natural gas or distillate oil; and

$H_r$  = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

#### **§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.**

(a) The SO<sub>2</sub> emission 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<sub>2</sub> control 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<sub>2</sub> emission rate (% P<sub>s</sub>) and the SO<sub>2</sub> emission rate (E<sub>s</sub>) 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<sub>2</sub> standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) 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<sub>2</sub> emission rate (E<sub>ho</sub>) and the 30-day average emission rate (E<sub>ao</sub>). 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<sub>2</sub> emission rate (%P<sub>s</sub>) 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<sub>s</sub> = Potential SO<sub>2</sub> emission rate, percent;

%R<sub>g</sub> = SO<sub>2</sub> removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%R<sub>f</sub> = SO<sub>2</sub> removal 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<sub>2</sub> emission rate (E<sub>ho</sub><sup>o</sup>) 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<sub>ao</sub><sup>o</sup>). The E<sub>ho</sub><sup>o</sup> is computed using the following formula:

$$E_{ho}^o = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E<sub>ho</sub><sup>o</sup> = Adjusted hourly SO<sub>2</sub> emission rate, ng/J (lb/MMBtu);

E<sub>ho</sub> = Hourly SO<sub>2</sub> emission rate, ng/J (lb/MMBtu);

E<sub>w</sub> = SO<sub>2</sub> concentration 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<sub>w</sub> for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X<sub>k</sub> = 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<sub>2</sub> emission rate (%P<sub>s</sub>), an adjusted %R<sub>g</sub> (%R<sub>g</sub><sup>o</sup>) is computed from the adjusted E<sub>ao</sub><sup>o</sup> from paragraph (b)(3)(i) of this section and an adjusted average SO<sub>2</sub> inlet rate (E<sub>ai</sub><sup>o</sup>) using the following formula:

$$\%R_g^o = 100 \left( 1.0 - \frac{E_{ao}^o}{E_{ai}^o} \right)$$

To compute E<sub>ai</sub><sup>o</sup>, an adjusted hourly SO<sub>2</sub> inlet rate (E<sub>hi</sub><sup>o</sup>) is used. The E<sub>hi</sub><sup>o</sup> is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hi}^{\circ}$  = Adjusted hourly SO<sub>2</sub> inlet rate, ng/J (lb/MMBtu); and

$E_{hi}$  = Hourly SO<sub>2</sub> inlet 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<sub>s</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO<sub>2</sub> 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<sub>2</sub> emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> emissions data in calculating %P<sub>s</sub> and E<sub>ho</sub> 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<sub>2</sub> emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating %P<sub>s</sub> and E<sub>ho</sub> pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO<sub>2</sub> control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate %P<sub>s</sub> or E<sub>s</sub> 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<sub>2</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub>) or CO<sub>2</sub> 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<sub>2</sub> or CO<sub>2</sub> 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<sub>x</sub> 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<sub>x</sub> under § 60.48(b).

(1) For the initial compliance test, NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left( \frac{H_z}{H_b} \right) (E_{zg} - E_{zg}) \quad (\text{Eq.1})$$

Where:

E = Emissions rate of NO<sub>x</sub> from the duct burner, ng/J (lb/MMBtu) heat input;

E<sub>sg</sub> = 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  $\text{NO}_x$  concentrations. Method 3A or 3B of appendix A of this part shall be used to determine  $\text{O}_2$  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  $\text{NO}_x$  and  $\text{O}_2$  and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The  $\text{NO}_x$  emissions rate at the outlet from the steam generating unit shall constitute the  $\text{NO}_x$  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  $\text{NO}_x$  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  $\text{NO}_x$  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<sub>2</sub> (or CO<sub>2</sub>) 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<sub>2</sub> (or CO<sub>2</sub>), 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) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit ( *i.e.*, reference method) data and performance test ( *i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see [http://www.epa.gov/ttn/chief/ert/ert\\_tool.html/](http://www.epa.gov/ttn/chief/ert/ert_tool.html/)) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

#### **§ 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<sub>2</sub> standards in § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO<sub>2</sub> concentrations and either O<sub>2</sub> or CO<sub>2</sub> concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO<sub>2</sub> and either O<sub>2</sub> or CO<sub>2</sub> concentrations shall both be monitored at the inlet and outlet of the SO<sub>2</sub> control device. If the owner or operator has installed and certified SO<sub>2</sub> and O<sub>2</sub> or CO<sub>2</sub> 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<sub>2</sub> concentration data and CO<sub>2</sub> (or O<sub>2</sub>) data are collected simultaneously; and

(2) In addition to meeting the applicable SO<sub>2</sub> and CO<sub>2</sub> (or O<sub>2</sub>) 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<sub>2</sub> and CO<sub>2</sub> (or O<sub>2</sub>) 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> input rate, or

(2) Measuring SO<sub>2</sub> according to Method 6B of appendix A of this part at the inlet or outlet to the SO<sub>2</sub> 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<sub>2</sub> and CO<sub>2</sub> 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<sub>2</sub> emission rate, E<sub>D</sub>, 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> CEMS at the inlet to the SO<sub>2</sub> control device is 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO<sub>2</sub> control device is 50 percent of the maximum estimated hourly potential SO<sub>2</sub> emissions of the fuel combusted. Alternatively, SO<sub>2</sub> 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 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<sub>2</sub> and O<sub>2</sub> monitors and for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> and O<sub>2</sub> monitors and for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2</sub> and NO<sub>x</sub> span values less than or equal to 30 ppm; and

(iii) For SO<sub>2</sub>, CO<sub>2</sub>, and O<sub>2</sub> monitoring systems and for NO<sub>x</sub> 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<sub>2</sub> (regardless of the SO<sub>2</sub> emission level during the RATA), and for NO<sub>x</sub> when the average NO<sub>x</sub> emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

[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 systems (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), (5), or (6) 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 within 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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(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 within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; 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 10 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<sub>x</sub> standard 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<sub>x</sub> and O<sub>2</sub> (or CO<sub>2</sub>) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO<sub>x</sub> emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

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

(d) The 1-hour average NO<sub>x</sub> emission rates measured by the continuous NO<sub>x</sub> monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

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

(1) 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<sub>x</sub> is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO<sub>x</sub> span values shall be determined as follows:

<b>Fuel</b>	<b>Span values for NO<sub>x</sub> (ppm)</b>
Natural gas	500.
Oil	500.
Coal	1,000.

<b>Fuel</b>	<b>Span values for NO<sub>x</sub> (ppm)</b>
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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) 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<sub>2</sub> emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to



reduce SO<sub>2</sub> 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<sub>2</sub> or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO<sub>2</sub>, 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 current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) 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.

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO<sub>2</sub> emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. 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. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

#### **§ 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<sub>2</sub>. 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<sub>2</sub>, PM, and/or NO<sub>x</sub> emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data

from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO<sub>x</sub> standard 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<sub>x</sub> emission rates ( *i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion ( *i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air ( *i.e.* , flue gas O<sub>2</sub> level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO<sub>x</sub> emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(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<sub>x</sub> standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO<sub>x</sub> emission rates (expressed as NO<sub>2</sub>) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO<sub>x</sub> 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<sub>x</sub> emission rates are in excess of the NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> or diluent (O<sub>2</sub> or CO<sub>2</sub>) 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.

(I) 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<sub>2</sub> 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 SO<sub>2</sub> or diluent (O<sub>2</sub> or CO<sub>2</sub>) 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<sub>2</sub> standards 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<sub>f</sub> ) is used to determine the overall percent reduction ( *i.e.* , %R<sub>o</sub> ) 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<sub>f</sub> ) 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<sub>x</sub> emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO<sub>x</sub> 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 (such as a current, valid purchase contract, tariff sheet, or transportation contract) 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<sub>x</sub> 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<sub>x</sub> emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO<sub>x</sub> 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<sub>x</sub> emission limit shall be determined by the compliance and performance test methods and procedures for NO<sub>x</sub> in § 60.46b(i).

(iii) The monitoring of the NO<sub>x</sub> emission 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 or operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO<sub>x</sub> standard 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<sub>x</sub> burner 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<sub>x</sub> emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO<sub>x</sub> emission 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<sub>x</sub> emission limit shall be determined by the compliance and performance test methods and procedures for NO<sub>x</sub> in § 60.46b.

(iii) The monitoring of the NO<sub>x</sub> emission 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 or 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<sub>x</sub> technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO<sub>x</sub> emissions 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<sub>2</sub> and/or NO<sub>x</sub> 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<sub>x</sub> standard 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<sub>x</sub> emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO<sub>x</sub> emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO<sub>x</sub> emissions shall be determined by the compliance and performance test methods and procedures for NO<sub>x</sub> in § 60.46b.

(ii) The monitoring of the NO<sub>x</sub> emissions 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<sub>x</sub> standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO<sub>x</sub>* . (i) When fossil fuel alone is combusted, the NO<sub>x</sub> emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO<sub>x</sub> emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO<sub>x</sub>* . (i) The NO<sub>x</sub> emissions shall be determined by the compliance and performance test methods and procedures for NO<sub>x</sub> in § 60.46b.

(ii) The monitoring of the NO<sub>x</sub> 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; 77 FR 9461, Feb. 16, 2012]

**Indiana Department of Environmental Management  
Office of Air Quality**

**Attachment B to a Part 70 Operating Permit**

Source Description and Location	
Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 60, Subpart Ga	
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**Subpart Ga - Standards of Performance for Nitric Acid Plants for which Construction, Reconstruction, or Modification Commenced after October 14, 2011**

Source: 77 FR 48445, Aug. 14, 2012, unless otherwise noted.

**§ 60.70a Applicability and designation of affected facility.**

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) This subpart applies to any nitric acid production unit that commences construction or modification after October 14, 2011.

**§ 60.71a Definitions.**

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

*Affirmative defense* means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

*Monitoring system malfunction* means a sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to implement monitoring system repairs in response to monitoring system malfunctions or out-of-control periods, and to return the monitoring system to operation as expeditiously as practicable.

*Nitric acid production unit* means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

*Operating day* means a 24-hour period beginning at 12:00 a.m. during which the nitric acid production unit operated at any time during this period.

*Weak nitric acid* means acid which is 30 to 70 percent in strength.

#### **§ 60.72a Standards.**

*Nitrogen oxides.* On and after the date on which the performance test required to be conducted by § 60.73a(e) is completed, you may not discharge into the atmosphere from any affected facility any gases which contain NO<sub>x</sub>, expressed as NO<sub>2</sub>, in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times.

#### **§ 60.73a Emissions testing and monitoring.**

(a) *General emissions monitoring requirements.* You must install and operate a NO<sub>x</sub> concentration (ppmv) continuous emissions monitoring system (CEMS). You must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO<sub>x</sub> concentration and stack gas flow rate, you will determine hourly NO<sub>x</sub> emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). You must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction.

(b) *Nitrogen oxides concentration continuous emissions monitoring system.* (1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NO<sub>x</sub> emissions in accordance with the provisions of § 60.13 and Performance Specification 2 of Appendix B and Procedure 1 of Appendix F of this part. You must use cylinder gas audits to fulfill the quarterly auditing requirement at section 5.1 of Procedure 1 of Appendix F of this part for the NO<sub>x</sub> concentration CEMS.

(2) For the NO<sub>x</sub> concentration CEMS, use a span value, as defined in Performance Specification 2, section 3.11, of Appendix B of this part, of 500 ppmv (as NO<sub>2</sub>). If you emit NO<sub>x</sub> at concentrations higher than 600 ppmv (e.g., during startup or shutdown periods), you must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NO<sub>x</sub> emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods.

(3) For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A-4 of this part; EPA Reference Method 320 of Appendix A of part 63 of this chapter; or ASTM D6348-03 (incorporated by reference, see § 60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of this section, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of this part) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of this part).

(4) If you use EPA Reference Method 7E of Appendix A-4 of this part, you must mitigate loss of NO<sub>2</sub> in water according to the requirements in paragraphs (b)(4)(i), (ii), or (iii) of this section and verify performance by conducting the system bias checks required in EPA Reference Method 7E, section 8, of Appendix A-4 of this part according to (b)(4)(iv) of this section, or follow the dynamic spike procedure according to paragraph (b)(4)(v) of this section.

(i) For a wet-basis measurement system, you must measure and report temperature of sample line and components (up to analyzer inlet) to demonstrate that the temperatures remain above the sample gas dew point at all times during the sampling.

(ii) You may use a dilution probe to reduce the dew point of the sample gas.

(iii) You may use a refrigerated-type condenser or similar device (e.g., permeation dryer) to remove condensate continuously from sample gas while maintaining minimal contact between condensate and sample gas.

(iv) If your analyzer measures nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>) separately, you must use both NO and NO<sub>2</sub> calibration gases. Otherwise, you must substitute NO<sub>2</sub> calibration gas for NO calibration gas in the performance of system bias checks.

(v) You must conduct dynamic spiking according to EPA Reference Method 7E, section 16.1, of Appendix A-4 of this part using NO<sub>2</sub> as the spike gas.

(5) Instead of a NO<sub>x</sub> concentration CEMS meeting Performance Specification 2, you may apply an FTIR CEMS meeting the requirements of Performance Specification 15 of Appendix B of this part to measure NO<sub>x</sub> concentrations. Should you use an FTIR CEMS, you must replace the Relative Accuracy Test Audit requirements of Procedure 1 of appendix F of this part with the validation requirements and criteria of Performance Specification 15, sections 11.1.1 and 12.0, of Appendix B of this part.

(c) *Determining NO<sub>x</sub> mass emissions rate values.* You must use the NO<sub>x</sub> concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NO<sub>x</sub>/ton of acid produced expressed as 100 percent nitric acid).

(1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NO<sub>x</sub> to produce data in units of mass rate (e.g., lb/hr) of NO<sub>x</sub> on an hourly basis. You will operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of § 60.13 and Performance Specification 6 of Appendix B of this part. You must comply with the following provisions in (c)(1)(i) through (iii) of this section.

(i) You must use a stack gas flow rate sensor with a full scale output of at least 125 percent of the maximum expected exhaust volumetric flow rate (see Performance Specification 6, section 8, of Appendix B of this part).

(ii) For conducting the relative accuracy test audits, per Performance Specification 6, section 8.2 of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, you must use either EPA Reference Method 2, 2F, or 2G of Appendix A-4 of this part. You may also apply Method 2H in conjunction with other velocity measurements.

(iii) You must verify that the CERMS complies with the quality assurance requirements in Procedure 1 of Appendix F of this part. You must conduct relative accuracy testing to provide for calculating the relative accuracy for RATA and RAA determinations in units of lb/hour.

(2) You must determine the nitric acid production parameters (production rate and concentration) by installing, calibrating, maintaining, and operating a permanent monitoring system (e.g., weigh scale, volume flow meter, mass flow meter, tank volume) to measure and record the weight rates of nitric acid produced in tons per hour. If your nitric acid production rate measurements are for periods longer than hourly (e.g., daily values), you will determine average hourly production values, tons acid/hr, by dividing

the total acid production by the number of hours of process operation for the subject measurement period. You must comply with the following provisions in (c)(2)(i) through (iv) of this section.

(i) You must verify that each component of the monitoring system has an accuracy and precision of no more than  $\pm 5$  percent of full scale.

(ii) You must analyze product concentration via titration or by determining the temperature and specific gravity of the nitric acid. You may also use ASTM E1584-11 (incorporated by reference, see § 60.17), for determining the concentration of nitric acid in percent. You must determine product concentration daily.

(iii) You must use the acid concentration to express the nitric acid production as 100 percent nitric acid.

(iv) You must record the nitric acid production, expressed as 100 percent nitric acid, and the hours of operation.

(3) You must calculate hourly  $\text{NO}_x$  emissions rates in units of the standard (lb/ton acid) for each hour of process operation. For process operating periods for which there is little or no acid production (e.g., startup or shutdown), you must use the average hourly acid production rate determined from the data collected over the previous 30 days of normal acid production periods (see § 60.75a).

(d) *Continuous monitoring system.* For each continuous monitoring system, including  $\text{NO}_x$  concentration measurement, volumetric flow rate measurement, and nitric acid production measurement equipment, you must meet the requirements in paragraphs (d)(1) through (3) of this section.

(1) You must operate the monitoring system and collect data at all required intervals at all times the affected facility is operating except for periods of monitoring system malfunctions or out-of-control periods as defined in Appendix F, sections 4 and 5, of this part, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(2) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in calculating emissions and the status of compliance with the applicable emissions limit in accordance with § 60.72a(a).

(e) *Initial performance testing.* You must conduct an initial performance test to demonstrate compliance with the  $\text{NO}_x$  emissions limit under § 60.72a(a) beginning in the calendar month following initial certification of the  $\text{NO}_x$  and flow rate monitoring CEMS. The initial performance test consists of collection of hourly  $\text{NO}_x$  average concentration, mass flow rate recorded with the certified  $\text{NO}_x$  concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. You must assure that the CERMS meets all of the data quality assurance requirements as per § 60.13 and Appendix F, Procedure 1, of this part and you must use the data from the CERMS for this compliance determination.

#### **§ 60.74a Affirmative defense for violations of emission standards during malfunction.**

In response to an action to enforce the standards set forth in § 60.72a, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to



meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging

period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

#### **§ 60.75a Calculations.**

(a) You must calculate the 30 operating day rolling arithmetic average emissions rate in units of the applicable emissions standard (lb NO<sub>x</sub> /ton 100 percent acid produced) at the end of each operating day using all of the quality assured hourly average CEMS data for the previous 30 operating days.

(b) You must calculate the 30 operating day average emissions rate according to Equation 1:

$$\frac{E_{30}}{P_i} = k \frac{1}{n} \sum_{i=1}^n C_i Q_i \quad (\text{Eq. 1})$$

Where:

E<sub>30</sub> = 30 operating day average emissions rate of NO<sub>x</sub> , lb NO<sub>x</sub> /ton of 100 percent HNO<sub>3</sub> ;

C<sub>i</sub> = concentration of NO<sub>x</sub> for hour i, ppmv;

Q<sub>i</sub> = volumetric flow rate of effluent gas for hour i, where C<sub>i</sub> and Q<sub>i</sub> are on the same basis (either wet or dry), scf/hr;

P<sub>i</sub> = total acid produced during production hour i, tons 100 percent HNO<sub>3</sub> ;

k = conversion factor, 1.194 × 10<sup>-7</sup> for NO<sub>x</sub> ; and

n = number of operating hours in the 30 operating day period, i.e., n is between 30 and 720.

#### **§ 60.76a Recordkeeping.**

(a) For the NO<sub>x</sub> emissions rate, you must keep records for and results of the performance evaluations of the continuous emissions monitoring systems.

(b) You must maintain records of the following information for each 30 operating day period:

(1) Hours of operation.

(2) Production rate of nitric acid, expressed as 100 percent nitric acid.

(3) 30 operating day average NO<sub>x</sub> emissions rate values.

(c) You must maintain records of the following time periods:

(1) Times when you were not in compliance with the emissions standards.

(2) Times when the pollutant concentration exceeded full span of the NO<sub>x</sub> monitoring equipment.

(3) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken.

(e) You must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications.

(f) For each malfunction, you must maintain records of the following information:

(1) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

#### **§ 60.77a Reporting.**

(a) The performance test data from the initial and subsequent performance tests and from the performance evaluations of the continuous monitors must be submitted to the Administrator at the appropriate address as shown in 40 CFR 60.4.

(b) The following information must be reported to the Administrator for each 30 operating day period where you were not in compliance with the emissions standard:

(1) Time period;

(2) NO<sub>x</sub> emission rates (lb/ton of acid produced);

(3) Reasons for noncompliance with the emissions standard; and

(4) Description of corrective actions taken.

(c) You must also report the following whenever they occur:

(1) Times when the pollutant concentration exceeded full span of the NO<sub>x</sub> pollutant monitoring equipment.

(2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications.

(e) Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, you must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ( [https://cdx.epa.gov/SSL/cdx/EPA\\_Home.asp](https://cdx.epa.gov/SSL/cdx/EPA_Home.asp) ). You must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) ( <http://www.epa.gov/ttn/chief/ert/index.html> ). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a

compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Mark the compact disk or other commonly used electronic storage media clearly as CBI and mail to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, you must also submit these reports to the delegated authority in the format specified by the delegated authority. You must submit the other information as required in the performance evaluation as described in § 60.2 and as required in this chapter.

(f) If a malfunction occurred during the reporting period, you must submit a report that contains the following:

(1) 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.

(2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with § 60.11(d), including actions taken to correct a malfunction.

## Indiana Department of Environmental Management Office of Air Quality

### Attachment C to a Part 70 Operating Permit

Source Description and Location
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 60, Subpart KKKK
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#### Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

#### § 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

#### Applicability

#### § 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

#### § 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides (NO<sub>x</sub>) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency

improvements are exempt from the NO<sub>x</sub> emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

## **Emission Limits**

### **§ 60.4315 What pollutants are regulated by this subpart?**

The pollutants regulated by this subpart are nitrogen oxide (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>).

### **§ 60.4320 What emission limits must I meet for nitrogen oxides (NO<sub>x</sub>)?**

(a) You must meet the emission limits for NO<sub>x</sub> specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO<sub>x</sub>.

### **§ 60.4325 What emission limits must I meet for NO<sub>x</sub> if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?**

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

### **§ 60.4330 What emission limits must I meet for sulfur dioxide (SO<sub>2</sub>)?**

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO<sub>2</sub>/J (0.060 lb SO<sub>2</sub>/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO<sub>2</sub> in excess of 65 ng SO<sub>2</sub>/J (0.15 lb SO<sub>2</sub>/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO<sub>2</sub> in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO<sub>2</sub> /J (0.42 lb SO<sub>2</sub> /MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

## **General Compliance Requirements**

### **§ 60.4333 What are my general requirements for complying with this subpart?**

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO<sub>x</sub> emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

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

## **Monitoring**

### **§ 60.4335 How do I demonstrate compliance for NO<sub>x</sub> if I use water or steam injection?**

(a) If you are using water or steam injection to control NO<sub>x</sub> emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO<sub>x</sub> monitor and a diluent gas (oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>)) monitor, to determine the hourly NO<sub>x</sub> emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

**§ 60.4340 How do I demonstrate continuous compliance for NO<sub>x</sub> if I do not use water or steam injection?**

(a) If you are not using water or steam injection to control NO<sub>x</sub> emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the NO<sub>x</sub> emission result from the performance test is less than or equal to 75 percent of the NO<sub>x</sub> emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO<sub>x</sub> emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO<sub>x</sub> formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO<sub>x</sub> mode.

(iii) For any turbine that uses SCR to reduce NO<sub>x</sub> emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO<sub>x</sub> emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

**§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?**

If the option to use a NO<sub>x</sub> CEMS is chosen:

(a) Each NO<sub>x</sub> diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO<sub>x</sub> diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in § 60.13(e)(2), during each full unit operating hour, both the NO<sub>x</sub> monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours,



at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO<sub>x</sub> emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

**§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?**

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO<sub>x</sub> and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO<sub>x</sub> emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O<sub>2</sub> concentration exceeds 19.0 percent O<sub>2</sub> (or the hourly average CO<sub>2</sub> concentration is less than 1.0 percent CO<sub>2</sub>), a diluent cap value of 19.0 percent O<sub>2</sub> or 1.0 percent CO<sub>2</sub> (as applicable) may be used in the emission calculations.

(c) Correction of measured NO<sub>x</sub> concentrations to 15 percent O<sub>2</sub> is not allowed.

(d) If you have installed and certified a NO<sub>x</sub> diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO<sub>x</sub> emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(\text{NO}_x)_b * (\text{HI})_b}{P} \quad (\text{Eq. 1})$$

Where:

E = hourly NO<sub>x</sub> emission rate, in lb/MWh,

(NO<sub>x</sub>)<sub>h</sub> = hourly NO<sub>x</sub> emission rate, in lb/MMBtu,

(HI)<sub>h</sub> = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad (\text{Eq. 2})$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)<sub>t</sub> = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)<sub>c</sub> = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad (\text{Eq. 3})$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10<sup>6</sup> = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \quad (\text{Eq. 4})$$

Where:

E = NO<sub>x</sub> emission rate in lb/MWh,

(NO<sub>x</sub>)<sub>m</sub> = NO<sub>x</sub> emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

#### **§ 60.4355 How do I establish and document a proper parameter monitoring plan?**

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO<sub>x</sub> emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO<sub>x</sub> emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at

the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the NO<sub>x</sub> emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

#### **§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?**

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

#### **§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?**

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO<sub>2</sub> /J (0.060 lb SO<sub>2</sub> /MMBtu) heat input for units located in continental areas and 180 ng SO<sub>2</sub> /J (0.42 lb SO<sub>2</sub> /MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO<sub>2</sub> /J (0.060 lb SO<sub>2</sub> /MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO<sub>2</sub> /J (0.42 lb SO<sub>2</sub> /MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO<sub>2</sub> /J (0.060 lb SO<sub>2</sub> /MMBtu) heat input for continental areas or 180 ng SO<sub>2</sub> /J (0.42 lb SO<sub>2</sub> /MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

**§ 60.4370 How often must I determine the sulfur content of the fuel?**

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter ( i.e. , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily

samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

## **Reporting**

### **§ 60.4375 What reports must I submit?**

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with § 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

### **§ 60.4380 How are excess emissions and monitor downtime defined for NO<sub>x</sub> ?**

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO<sub>x</sub> control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average  $\text{NO}_x$  emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a "4-hour rolling average  $\text{NO}_x$  emission rate" is the arithmetic average of the average  $\text{NO}_x$  emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average  $\text{NO}_x$  emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid  $\text{NO}_x$  emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average  $\text{NO}_x$  emission rate" is the arithmetic average of all hourly  $\text{NO}_x$  emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly  $\text{NO}_x$  emissions rates for the preceding 30 unit operating days if a valid  $\text{NO}_x$  emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid:  $\text{NO}_x$  concentration,  $\text{CO}_2$  or  $\text{O}_2$  concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the  $\text{NO}_x$  emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

#### **§ 60.4385 How are excess emissions and monitoring downtime defined for $\text{SO}_2$ ?**

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue

to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

**§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?**

(a) If you operate an emergency combustion turbine, you are exempt from the NO<sub>x</sub> limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO<sub>x</sub> limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

**§ 60.4395 When must I submit my reports?**

All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

**Performance Tests**

**§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO<sub>x</sub> ?**

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO<sub>x</sub> concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO<sub>x</sub> emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_x)_c * Q_{std}}{P} \quad (\text{Eq. 5})$$

Where:

E = NO<sub>x</sub> emission rate, in lb/MWh

$1.194 \times 10^{-7}$  = conversion constant, in lb/dscf-ppm

(NO<sub>x</sub>)<sub>c</sub> = average NO<sub>x</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr



P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(ii) Measure the NO<sub>x</sub> and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO<sub>x</sub> emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO<sub>x</sub> emission rate in lb/MWh.

(2) Sampling traverse points for NO<sub>x</sub> and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO<sub>x</sub> and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO<sub>x</sub> concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO<sub>x</sub> concentration during the stratification test; or

(B) For turbines with a NO<sub>x</sub> standard greater than 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points; or

(C) For turbines with a NO<sub>x</sub> standard less than or equal to 15 ppm @ 15% O<sub>2</sub>, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO<sub>x</sub> concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO<sub>2</sub> (or O<sub>2</sub>) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO<sub>x</sub> emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO<sub>x</sub> with no additional post-combustion NO<sub>x</sub> control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO<sub>x</sub> emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO<sub>x</sub> emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

**§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO<sub>x</sub> -diluent CEMS?**

If you elect to install and certify a NO<sub>x</sub> -diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO<sub>x</sub> emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO<sub>x</sub> emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

**§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?**

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO<sub>x</sub> emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

**§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?**

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent SO<sub>2</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see § 60.17) for natural gas or ASTM D4177 (incorporated by reference, see § 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17).

(2) Measure the SO<sub>2</sub> concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO<sub>2</sub> emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad (\text{Eq. 6})$$

Where:

E = SO<sub>2</sub> emission rate, in lb/MWh

$1.664 \times 10^{-7}$  = conversion constant, in lb/dscf-ppm

(SO<sub>2</sub>)<sub>c</sub> = average SO<sub>2</sub> concentration for the run, in ppm

Q<sub>std</sub> = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful

recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(3) Measure the SO<sub>2</sub> and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO<sub>2</sub> emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO<sub>2</sub> emission rate in lb/MWh.

(b) [Reserved]

## Definitions

### § 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

*Biogas* means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO<sub>2</sub>.

*Combined cycle combustion turbine* means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

*Combined heat and power combustion turbine* means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

*Combustion turbine model* means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

*Combustion turbine test cell/stand* means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

*Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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

*Efficiency* means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

*Emergency combustion turbine* means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the

local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

*Excess emissions* means a specified averaging period over which either (1) the NO<sub>x</sub> emissions are higher than the applicable emission limit in § 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

*Gross useful output* means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

*Heat recovery steam generating unit* means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

*Integrated gasification combined cycle electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

*ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

*Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

*Natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

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

*Peak load* means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

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

*Simple cycle combustion turbine* means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

*Stationary 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), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

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

*Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

*Useful thermal output* means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

**Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines**

<b>Combustion turbine type</b>	<b>Combustion turbine heat input at peak load (HHV)</b>	<b>NO<sub>x</sub> emission standard</b>
New turbine firing natural gas, electric generating	50 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	50 MMBtu/h	100 ppm at 15 percent O <sub>2</sub> or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	50 MMBtu/h and 850 MMBtu/h	25 ppm at 15 percent O <sub>2</sub> or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	850 MMBtu/h	15 ppm at 15 percent O <sub>2</sub> or 54 ng/J of useful output (0.43 lb/MWh).

<b>Combustion turbine type</b>	<b>Combustion turbine heat input at peak load (HHV)</b>	<b>NO<sub>x</sub> emission standard</b>
New turbine firing fuels other than natural gas, electric generating	50 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	50 MMBtu/h and 850 MMBtu/h	74 ppm at 15 percent O <sub>2</sub> or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	50 MMBtu/h	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	50 MMBtu/h and 850 MMBtu/h	42 ppm at 15 percent O <sub>2</sub> or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	50 MMBtu/h and 850 MMBtu/h	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	30 MW output	150 ppm at 15 percent O <sub>2</sub> or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	30 MW output	96 ppm at 15 percent O <sub>2</sub> or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O <sub>2</sub> or 110 ng/J of useful output (0.86 lb/MWh).

## Indiana Department of Environmental Management Office of Air Quality

### Attachment D to a Part 70 Operating Permit

Source Description and Location	
Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 60, Subpart VVa	
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**Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commences after November 7, 2006**

Source: 72 FR 64883, Nov. 16, 2007, unless otherwise noted.

**§ 60.480a Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482-1a through 60.482-11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482-1a through 60.482-11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482-1a through 60.482-11a.



(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482-1a through 60.482-11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F 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 that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart 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 F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§ 60.482-1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of § 60.485a(d), (e), and (f), and § 60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H 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 that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) *Stay of standards.* (1) Owners or operators that start a new, reconstructed, or modified affected source prior to November 16, 2007 are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “capital expenditure” in § 60.481a of this subpart. While the definition of “capital expenditure” is stayed, owners or operators should use the definition found in § 60.481 of subpart VV of this part.

(ii) [Reserved]

(2) Owners or operators are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the FEDERAL REGISTER .

(i) The definition of “process unit” in § 60.481a of this subpart. While the definition of “process unit” is stayed, owners or operators should use the following definition:

*Process unit* means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

(ii) The method of allocation of shared storage vessels in § 60.482-1a(g) of this subpart.

(iii) The standards for connectors in gas/vapor service and in light liquid service in § 60.482-11a of this subpart.

[72 FR 64883, Nov. 16, 2007, as amended at 73 FR 31375, June 2, 2008]

#### **§ 60.481a Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

*Capital expenditure* means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation:  $P = R \times A$ , where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation:  $Y = 1.0 - 0.575 \log X$ , where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

**TABLE FOR DETERMINING APPLICABLE VALUE FOR B**

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

*Closed-loop system* means an enclosed system that returns process fluid to the process.

*Closed-purge system* means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids 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 to a process.

*Connector* means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

*Control device* means an enclosed combustion device, vapor recovery system, or flare.

*Distance piece* means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

*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, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any 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 using best practices.

*Fuel gas* means gases that are combusted to derive useful work or heat.

*Fuel gas system* means the offsite and onsite piping and flow and pressure 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-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 judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007-2300).

*In gas/vapor service* means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

*In heavy liquid service* means that the piece of equipment is not in gas/vapor service or in light liquid service.

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e).

*In-situ sampling systems* means nonextractive samplers or in-line samplers.

*In vacuum service* means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

*In VOC service* means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

*Initial calibration value* means the concentration measured during the initial calibration at the beginning of each day required in § 60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

*Liquids dripping* means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

*Open-ended valve or line* means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

*Pressure release* means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

*Process improvement* means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in 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 accomplished. The following are not considered process unit shutdowns:

(1) 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.

(2) 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.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

*Quarter* means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

*Repaired* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482-2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482-3a(f), and 60.482-10a(f)(1)(ii), is re-monitored as specified in § 60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

*Replacement cost* means the capital needed to purchase all the depreciable components in a facility.

*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 nonroutine grab samples is not considered a sampling connection system.

*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.

*Storage vessel* means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

*Synthetic organic chemicals manufacturing industry* means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

*Transfer rack* means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

*Volatile organic compounds* or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.481a, the definitions of "capital expenditure" and "process unit" were stayed until further notice.

#### **§ 60.482-1a Standards: General.**

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482-1a through 60.482-10a or § 60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in § 60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, or 60.482-10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482-2a through 60.482-10a if it is identified as required in § 60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482-2a through 60.482-11a if it is identified as required in § 60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§ 60.482-2a, 60.482-7a, and 60.483.2a:

Operating time (percent of hours during year)	Equivalent 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 quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time 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. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually ( *i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, in § 60.482-1a, paragraph (g) was stayed until further notice.

**§ 60.482-2a Standards: Pumps in light liquid service.**

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b), except as provided in § 60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482-1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482-1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in § 60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(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 § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump 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 (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 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 § 60.482-10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC 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)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in § 60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485a(c); and



(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is 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 § 60.482-10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) 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 practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

**§ 60.482-3a Standards: Compressors.**

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1a(c) and paragraphs (h), (i), and (j) 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 § 60.482-10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) 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 checked daily or shall be equipped with an audible alarm.

(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 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 § 60.482-9a.

(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) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482-10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm 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 no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485a(c); 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.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

#### **§ 60.482-4a 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 no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485a(c).

(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 through the pressure relief device to a control device as described in § 60.482-10a is exempted 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 new 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 § 60.482-9a.

**§ 60.482-5a 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 § 60.482-1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) 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;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is 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.

**§ 60.482-6a 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 § 60.482-1a(c) 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.

(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 paragraphs (a) through (c) of this section.

**§ 60.482-7a Standards: Valves in gas/vapor service and in light liquid service.**

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c) and (f), and §§ 60.483-1a and 60.483-2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482-1a(c), and §§ 60.483-1a and 60.483-2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with § 60.483-1a or § 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(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 § 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;
- (3) Tightening of packing gland nuts;
- (4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- (1) Has no external actuating mechanism in contact with the process fluid,
- (2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485a(c), and
- (3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- (1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- (2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through § 60.14 or § 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

**§ 60.482-8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.**

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater 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 § 60.482-9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482-2a(c)(2) and 60.482-7a(e).

**§ 60.482-9a Standards: Delay of repair.**

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are 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 § 60.482-10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, 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 next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

**§ 60.482-10a 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.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices 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 designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); 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 ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) 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.

(h) 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.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(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 paragraphs (f)(1)(i) 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.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(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 process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.



(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486a(c).

(4) For each inspection conducted in accordance with § 60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

**§ 60.482-11a Standards: Connectors in gas/vapor service and in light liquid service.**

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in § 60.482-1a(c), § 60.482-10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, § 60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$  = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

$C_L$  = Number of connectors measured at 500 ppm or greater, by the method specified in § 60.485a(b).

$C_t$  = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors*. (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(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 that 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 (7 feet) 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, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors 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.

EFFECTIVE DATE NOTE: At 73 FR 31376, June 2, 2008, § 60.482-11a was stayed until further notice.

**§ 60.483-1a Alternative standards for valves—allowable percentage of valves leaking.**

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485a(h).

**§ 60.483-2a Alternative standards for valves—skip period leak detection and repair.**

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in

accordance with § 60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

**§ 60.484a Equivalence of means of emission limitation.**

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent 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 approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER .

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

#### **§ 60.485a Test methods and procedures.**

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. 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 ppm 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 ppm. 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.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of

more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260-73, 91, or 96, E168-67, 77, or 92, E169-63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H<sub>2</sub>O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H<sub>2</sub>O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{\max} = K_1 + K_2 H_T$$

Where:

$V_{\max}$  = Maximum permitted velocity, m/sec (ft/sec).

$H_T$  = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

$K_1$  = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

$K_2$  = 0.7084 m<sup>4</sup>/(MJ-sec) (metric units) = 0.087 ft<sup>4</sup>/(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

$K$  = Conversion constant, 1.740×10<sup>-7</sup> (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10<sup>-6</sup> [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

$C_i$  = Concentration of sample component "i," ppm

$H_i$  = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see § 60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483-1a or § 60.483-2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$



Where:

$\%V_L$  = Percent leaking valves.

$V_L$  = Number of valves found leaking.

$V_T$  = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

**§ 60.486a Recordkeeping requirements.**

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482-7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in § 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonreparable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482-10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482-10a(e), 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.

(4) Periods when the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

(ii) The designation of equipment as subject to the requirements of § 60.482-2a(e), § 60.482-3a(i), or § 60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482-4a.

(4)(i) The dates of each compliance test as required in §§ 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and § 60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.

(v) Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in § 60.482-11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to § 60.482-4a.

(f) The following information pertaining to all valves subject to the requirements of § 60.482-7a(g) and (h), all pumps subject to the requirements of § 60.482-2a(g), and all connectors subject to the requirements of § 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483-2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

#### **§ 60.487a Reporting requirements.**

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7a(f).

(3) Number of pumps subject to the requirements of § 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2a(e) and those pumps complying with § 60.482-2a(f).

(4) Number of compressors subject to the requirements of § 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3a(i) and those compressors complying with § 60.482-3a(h).

(5) Number of connectors subject to the requirements of § 60.482-11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482-7a(b) or § 60.483-2a,

(ii) Number of valves for which leaks were not repaired as required in § 60.482-7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482-2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482-3a(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482-3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in § 60.482-11a(b)

(viii) Number of connectors for which leaks were not repaired as required in § 60.482-11a(d), and

(ix)-(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

#### **§ 60.488a Reconstruction.**

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under § 60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in § 60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

#### **§ 60.489a List of chemicals produced by affected facilities.**

Process units that produce, as intermediates or final products, chemicals listed in § 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

## Indiana Department of Environmental Management Office of Air Quality

### Attachment E to a Part 70 Operating Permit

Source Description and Location
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 60, Subpart IIII
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**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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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)  $9.0 \cdot n^{-0.20}$  g/KW-hr ( $6.7 \cdot n^{-0.20}$  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<sub>x</sub> 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)  $45 \cdot n^{-0.2}$  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, limit the emissions of NO<sub>x</sub> 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) 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 use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(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; 78 FR 6695, Jan. 30, 2013]

## **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<sub>x</sub> 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<sub>x</sub> 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) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. 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 calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see

§ 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(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; 78 FR 6695, Jan. 30, 2013]

### **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:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad (\text{Eq. 1})$$

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:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 2})$$

Where:

$C_i$  = concentration of  $\text{NO}_x$  or PM at the control device inlet,

$C_o$  = concentration of  $\text{NO}_x$  or PM at the control device outlet, and

R = percent reduction of  $\text{NO}_x$  or PM emissions.

(2) You must normalize the  $\text{NO}_x$  or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen ( $\text{O}_2$ ) using Equation 3 of this section, or an equivalent percent carbon dioxide ( $\text{CO}_2$ ) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% \text{O}_2} \quad (\text{Eq. 3})$$

Where:

$C_{adj}$  = Calculated  $\text{NO}_x$  or PM concentration adjusted to 15 percent  $\text{O}_2$ .

$C_d$  = Measured concentration of  $\text{NO}_x$  or PM, uncorrected.

5.9 = 20.9 percent  $\text{O}_2$  - 15 percent  $\text{O}_2$ , the defined  $\text{O}_2$  correction value, percent.

$\% \text{O}_2$  = Measured  $\text{O}_2$  concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent  $\text{O}_2$  and  $\text{CO}_2$  concentration is measured in lieu of  $\text{O}_2$  concentration measurement, a  $\text{CO}_2$  correction factor is needed. Calculate the  $\text{CO}_2$  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:

$$F_o = \frac{0.209}{F_c} \quad (\text{Eq. 4})$$

Where:

$F_o$  = Fuel factor based on the ratio of  $\text{O}_2$  volume to the ultimate  $\text{CO}_2$  volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is  $\text{O}_2$ , percent/100.

$F_d$  = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19,  $\text{dsm}^3/\text{J}$  ( $\text{dscf}/10^6 \text{ Btu}$ ).

$F_c$  = Ratio of the volume of  $\text{CO}_2$  produced to the gross calorific value of the fuel from Method 19,  $\text{dsm}^3/\text{J}$  ( $\text{dscf}/10^6 \text{ Btu}$ ).

(ii) Calculate the  $\text{CO}_2$  correction factor for correcting measurement data to 15 percent  $\text{O}_2$ , as follows:

$$X_{\text{CO}_2} = \frac{5.9}{F_o} \quad (\text{Eq. 5})$$

Where:

$X_{CO_2}$  =  $CO_2$  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:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (\text{Eq. 6})$$

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:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq. 7})$$

Where:

ER = Emission rate in grams per KW-hour.

$C_d$  = Measured  $NO_x$  concentration in ppm.

$1.912 \times 10^{-3}$  = 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:

$$ER = \frac{C_{adj} \times Q \times T}{KW\text{-hour}} \quad (\text{Eq. 8})$$

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.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ( [www.epa.gov/cdx](http://www.epa.gov/cdx) ). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

### **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  $\text{NO}_x$  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)  $45 \cdot n^{-0.2}$  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, limit the emissions of  $\text{NO}_x$  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) 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 reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. 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.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

*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.

**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]

<b>Maximum engine power</b>	<b>Emission standards for stationary pre-2007 model year engines with a displacement of &lt;10 liters per cylinder and 2007-2010 model year engines &gt;2,237 KW (3,000 HP) and with a displacement of &lt;10 liters per cylinder in g/KW-hr (g/HP-hr)</b>				
	<b>NMHC + NO<sub>x</sub></b>	<b>HC</b>	<b>NO<sub>x</sub></b>	<b>CO</b>	<b>PM</b>
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]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO <sub>x</sub> + 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)

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**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) <sup>1</sup>
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

<sup>1</sup>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 <sub>x</sub>	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+ <sup>1</sup>	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+ <sup>1</sup>	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+ <sup>2</sup>	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+ <sup>3</sup>	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+ <sup>3</sup>	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)

<sup>1</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> 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 <sup>1</sup>	Torque (percent) <sup>2</sup>	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

<sup>1</sup> Engine speed: ±2 percent of point.

<sup>2</sup> 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 <sub>x</sub> 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 <sub>2</sub> at the inlet and outlet of the	(2) Method 3, 3A, or 3B of 40 CFR part	(b) Measurements to determine

For each	Complying with the requirement to	You must	Using	According to the following requirements
		control device;	60, appendix A	O <sub>2</sub> concentration must be made at the same time as the measurements for NO <sub>x</sub> 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 <sub>x</sub> concentration.
		iv. Measure NO <sub>x</sub> 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 <sub>x</sub> concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO <sub>x</sub> 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 <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurement for NO <sub>x</sub> concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO <sub>x</sub> concentration.
		iv. Measure NO <sub>x</sub> at the exhaust of the	(4) Method 7E of 40 CFR part 60,	(d) NO <sub>x</sub> concentration must be at 15 percent

For each	Complying with the requirement to	You must	Using	According to the following requirements
		stationary internal combustion engine	appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	O <sub>2</sub> , 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 <sub>2</sub> 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 <sub>2</sub> concentration must be made at the same time as the measurements for PM 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	(c) Measurements to determine and moisture content must 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 <sub>2</sub> , 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 <sub>2</sub> concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal	(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

For each	Complying with the requirement to	You must	Using	According to the following requirements
		combustion engine exhaust at the sampling port location; and		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 <sub>2</sub> , 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.

<b>General Provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

**Indiana Department of Environmental Management  
Office of Air Quality**

**Attachment F to a Part 70 Operating Permit**

Source Description and Location	
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 61, Subpart FF
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**Subpart FF - National Emission Standard for Benzene Waste Operations**

Source: 55 FR 8346, Mar. 7, 1990, unless otherwise noted.

**§ 61.340 Applicability.**

(a) The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries.

(b) The provisions of this subpart apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any facility listed in paragraph (a) of this section. The waste streams at hazardous waste treatment, storage, and disposal facilities subject to the provisions of this subpart are the benzene-containing hazardous waste from any facility listed in paragraph (a) of this section. A hazardous waste treatment, storage, and disposal facility is a facility that must obtain a hazardous waste management permit under subtitle C of the Solid Waste Disposal Act.

(c) At each facility identified in paragraph (a) or (b) of this section, the following waste is exempt from the requirements of this subpart:

(1) Waste in the form of gases or vapors that is emitted from process fluids:

(2) Waste that is contained in a segregated stormwater sewer system.

(d) At each facility identified in paragraph (a) or (b) of this section, any gaseous stream from a waste management unit, treatment process, or wastewater treatment system routed to a fuel gas system, as defined in § 61.341, is exempt from this subpart. No testing, monitoring, recordkeeping, or reporting is required under this subpart for any gaseous stream from a waste management unit, treatment process, or wastewater treatment unit routed to a fuel gas system.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

## **§ 61.341 Definitions.**

*Benzene concentration* means the fraction by weight of benzene in a waste as determined in accordance with the procedures specified in § 61.355 of this subpart.

*Car-seal* means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

*Chemical manufacturing plant* means any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals. Examples of chemical manufacturing plants include facilities at which process units are operated to produce one or more of the following chemicals: benzenesulfonic acid, benzene, chlorobenzene, cumene, cyclohexane, ethylene, ethylbenzene, hydroquinone, linear alkylbenzene, nitrobenzene, resorcinol, sulfolane, or styrene.

*Closed-vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission source to a control device.

*Coke by-product recovery plant* means any facility designed and operated for the separation and recovery of coal tar derivatives (by-products) evolved from coal during the coking process of a coke oven battery.

*Container* means any portable waste management unit in which a material is stored, transported, treated, or otherwise handled. Examples of containers are drums, barrels, tank trucks, barges, dumpsters, tank cars, dump trucks, and ships.

*Control device* means an enclosed combustion device, vapor recovery system, or flare.

*Cover* means a device or system which is placed on or over a waste placed in a waste management unit so that the entire waste surface area is enclosed and sealed to minimize air emissions. A cover may have openings necessary for operation, inspection, and maintenance of the waste management unit such as access hatches, sampling ports, and gauge wells provided that each opening is closed and sealed when not in use. Example of covers include a fixed roof installed on a tank, a lid installed on a container, and an air-supported enclosure installed over a waste management unit.

*External floating roof* means a pontoon-type or double-deck type cover with certain rim sealing mechanisms that rests on the liquid surface in a waste management unit with no fixed roof.

*Facility* means all process units and product tanks that generate waste within a stationary source, and all waste management units that are used for waste treatment, storage, or disposal within a stationary source.

*Fixed roof* means a cover that is mounted on a waste management unit in a stationary manner and that does not move with fluctuations in liquid level.

*Floating roof* means a cover with certain rim sealing mechanisms consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and unit wall.



*Flow indicator* means a device which indicates whether gas flow is present in a line or vent system.

*Fuel gas system* means the offsite and onsite piping and control system that gathers gaseous streams generated by facility operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside the facility. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric.

*Individual drain system* means the system used to convey waste from a process unit, product storage tank, or waste management unit to a waste management unit. The term includes all process drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the receiving waste management unit.

*Internal floating roof* means a cover that rests or floats on the liquid surface inside a waste management unit that has a fixed roof.

*Liquid-mounted seal* means a foam or liquid-filled primary seal mounted in contact with the liquid between the waste management unit wall and the floating roof continuously around the circumference.

*Loading* means the introduction of waste into a waste management unit but not necessarily to complete capacity (also referred to as filling).

*Maximum organic vapor pressure* means the equilibrium partial pressure exerted by the waste at the temperature equal to the highest calendar-month average of the waste storage temperature for waste stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for waste stored at the ambient temperature, as determined:

- (1) In accordance with § 60.17(c); or
- (2) As obtained from standard reference texts; or
- (3) In accordance with § 60.17(a)(37); or
- (4) Any other method approved by the Administrator.

*No detectable emissions* means less than 500 parts per million by volume (ppmv) above background levels, as measured by a detection instrument reading in accordance with the procedures specified in § 61.355(h) of this subpart.

*Oil-water separator* means a waste management unit, generally a tank or surface impoundment, used to separate oil from water. An oil-water separator consists of not only the separation unit but also the forebay and other separator basins, skimmers, weirs, grit chambers, sludge hoppers, and bar screens that are located directly after the individual drain system and prior to additional treatment units such as an air flotation unit, clarifier, or biological treatment unit. Examples of an oil-water separator include an API separator, parallel-plate interceptor, and corrugated-plate interceptor with the associated ancillary equipment.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Point of waste generation* means the location where the waste stream exits the process unit component or storage tank prior to handling or treatment in an operation that is not an integral part of the production process, or in the case of waste management units that generate new wastes after treatment, the location where the waste stream exits the waste management unit component.

*Process unit* means equipment assembled and connected by pipes or ducts to produce intermediate or final products. A process unit can be operated independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

*Process unit turnaround* means the shutting down of the operations of a process unit, the purging of the contents of the process unit, the maintenance or repair work, followed by restarting of the process.

*Process unit turnaround waste* means a waste that is generated as a result of a process unit turnaround.

*Process wastewater* means water which comes in contact with benzene during manufacturing or processing operations conducted within a process unit. Process wastewater is not organic wastes, process fluids, product tank drawdown, cooling tower blowdown, steam trap condensate, or landfill leachate.

*Process wastewater stream* means a waste stream that contains only process wastewater.

*Product tank* means a stationary unit that is designed to contain an accumulation of materials that are fed to or produced by a process unit, and is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

*Product tank drawdown* means any material or mixture of materials discharged from a product tank for the purpose of removing water or other contaminants from the product tank.

*Safety device* means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. For the purpose of this subpart, a safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in this vapor headspace in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes, standard engineering codes and practices, or other requirements for the safe handling of flammable, ignitable, explosive, reactive, or hazardous materials.

*Segregated stormwater sewer system* means a drain and collection system designed and operated for the sole purpose of collecting rainfall runoff at a facility, and which is segregated from all other individual drain systems.

*Sewer line* means a lateral, trunk line, branch line, or other enclosed conduit used to convey waste to a downstream waste management unit.

*Slop oil* means the floating oil and solids that accumulate on the surface of an oil-water separator.

*Sour water stream* means a stream that:

(1) Contains ammonia or sulfur compounds (usually hydrogen sulfide) at concentrations of 10 ppm by weight or more;

(2) Is generated from separation of water from a feed stock, intermediate, or product that contained ammonia or sulfur compounds; and

(3) Requires treatment to remove the ammonia or sulfur compounds.

*Sour water stripper* means a unit that:

(1) Is designed and operated to remove ammonia or sulfur compounds (usually hydrogen sulfide) from sour water streams;

(2) Has the sour water streams transferred to the stripper through hard piping or other enclosed system; and

(3) Is operated in such a manner that the offgases are sent to a sulfur recovery unit, processing unit, incinerator, flare, or other combustion device.

*Surface impoundment* means a waste management unit which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or waste containing free liquids, and which is not an injection well. Examples of surface impoundments are holding, storage, settling, and aeration pits, ponds, and lagoons.

*Tank* means a stationary waste management unit that is designed to contain an accumulation of waste and is constructed primarily of nonearthen materials (e.g., wood, concrete, steel, plastic) which provide structural support.

*Treatment process* means a stream stripping unit, thin-film evaporation unit, waste incinerator, or any other process used to comply with § 61.348 of this subpart.

*Vapor-mounted seal* means a foam-filled primary seal mounted continuously around the perimeter of a waste management unit so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the unit wall, the liquid surface, and the floating roof.

*Waste* means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

*Waste management unit* means a piece of equipment, structure, or transport mechanism used in handling, storage, treatment, or disposal of waste. Examples of a waste management unit include a tank, surface impoundment, container, oil-water separator, individual drain system, steam stripping unit, thin-film evaporation unit, waste incinerator, and landfill.

*Waste stream* means the waste generated by a particular process unit, product tank, or waste management unit. The characteristics of the waste stream (e.g., flow rate, benzene concentration, water content) are determined at the point of waste generation. Examples of a waste stream include process wastewater, product tank drawdown, sludge and slop oil removed from waste management units, and landfill leachate.

*Wastewater treatment system* means any component, piece of equipment, or installation that receives, manages, or treats process wastewater, product tank drawdown, or landfill leachate prior to

direct or indirect discharge in accordance with the National Pollutant Discharge Elimination System permit regulations under 40 CFR part 122. These systems typically include individual drain systems, oil-water separators, air flotation units, equalization tanks, and biological treatment units.

*Water seal controls* means a seal pot, p-leg trap, or other type of trap filled with water (e.g., flooded sewers that maintain water levels adequate to prevent air flow through the system) that creates a water barrier between the sewer line and the atmosphere. The water level of the seal must be maintained in the vertical leg of a drain in order to be considered a water seal.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 67 FR 68531, Nov. 12, 2002]

#### **§ 61.342 Standards: General.**

(a) An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section. The total annual benzene quantity from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent. The benzene quantity in a waste stream is to be counted only once without multiple counting if other waste streams are mixed with or generated from the original waste stream. Other specific requirements for calculating the total annual benzene waste quantity are as follows:

(1) Wastes that are exempted from control under §§ 61.342(c)(2) and 61.342(c)(3) are included in the calculation of the total annual benzene quantity if they have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(2) The benzene in a material subject to this subpart that is sold is included in the calculation of the total annual benzene quantity if the material has an annual average water content greater than 10 percent.

(3) Benzene in wastes generated by remediation activities conducted at the facility, such as the excavation of contaminated soil, pumping and treatment of groundwater, and the recovery of product from soil or groundwater, are not included in the calculation of total annual benzene quantity for that facility. If the facility's total annual benzene quantity is 10 Mg/yr (11 ton/yr) or more, wastes generated by remediation activities are subject to the requirements of paragraphs (c) through (h) of this section. If the facility is managing remediation waste generated offsite, the benzene in this waste shall be included in the calculation of total annual benzene quantity in facility waste, if the waste streams have an annual average water content greater than 10 percent, or if they are mixed with water or other wastes at any time and the mixture has an annual average water content greater than 10 percent.

(4) The total annual benzene quantity is determined based upon the quantity of benzene in the waste before any waste treatment occurs to remove the benzene except as specified in § 61.355(c)(1)(i) (A) through (C).

(b) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall be in compliance with the requirements of paragraphs (c) through (h) of this section no later than 90 days following the effective date, unless a waiver of compliance has been obtained under § 61.11, or by the initial startup for a new source with an initial startup after the effective date.

(1) The owner or operator of an existing source unable to comply with the rule within the required time may request a waiver of compliance under § 61.10.

(2) As part of the waiver application, the owner or operator shall submit to the Administrator a plan under § 61.10(b)(3) that is an enforceable commitment to obtain environmental benefits to mitigate the benzene emissions that result from extending the compliance date. The plan shall include the following information:

(i) A description of the method of compliance, including the control approach, schedule for installing controls, and quantity of the benzene emissions that result from extending the compliance date;

(ii) If the control approach involves a compliance strategy designed to obtain integrated compliance with multiple regulatory requirements, a description of the other regulations involved and their effective dates; and

(iii) A description of the actions to be taken at the facility to obtain mitigating environmental benefits, including how the benefits will be obtained, the schedule for these actions, and an estimate of the quantifiable benefits that directly result from these actions.

(c) Each owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section shall manage and treat the facility waste as follows:

(1) For each waste stream that contains benzene, including (but not limited to) organic waste streams that contain less than 10 percent water and aqueous waste streams, even if the wastes are not discharged to an individual drain system, the owner or operator shall:

(i) Remove or destroy the benzene contained in the waste using a treatment process or wastewater treatment system that complies with the standards specified in § 61.348 of this subpart.

(ii) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste stream prior to and during treatment of the waste stream in accordance with paragraph (c)(1)(i) of this section.

(iii) Each waste management unit used to manage or treat waste streams that will be recycled to a process shall comply with the standards specified in §§ 61.343 through 61.347. Once the waste stream is recycled to a process, including to a tank used for the storage of production process feed, product, or product intermediates, unless this tank is used primarily for the storage of wastes, the material is no longer subject to paragraph (c) of this section.

(2) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in § 61.355(c)(2) or § 61.355(c)(3).

(3) A waste stream is exempt from paragraph (c)(1) of this section provided that the owner or operator demonstrates initially and, thereafter, at least once per year that the conditions specified in either paragraph (c)(3)(i) or (c)(3)(ii) of this section are met.

(i) The waste stream is process wastewater that has a flow rate less than 0.02 liters per minute (0.005 gallons per minute) or an annual wastewater quantity of less than 10 Mg/yr (11 ton/yr); or

(ii) All of the following conditions are met:

(A) The owner or operator does not choose to exempt process wastewater under paragraph (c)(3)(i) of this section,

(B) The total annual benzene quantity in all waste streams chosen for exemption in paragraph (c)(3)(ii) of this section does not exceed 2.0 Mg/yr (2.2 ton/yr) as determined in the procedures in § 61.355(j), and

(C) The total annual benzene quantity in a waste stream chosen for exemption, including process unit turnaround waste, is determined for the year in which the waste is generated.

(d) As an alternative to the requirements specified in paragraphs (c) and (e) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste other than process wastewater in accordance with the requirements of paragraph (c)(1) of this section.

(2) The owner or operator shall manage and treat process wastewater in accordance with the following requirements:

(i) Process wastewater shall be treated to achieve a total annual benzene quantity from facility process wastewater less than 1 Mg/yr (1.1 ton/yr). Total annual benzene from facility process wastewater shall be determined by adding together the annual benzene quantity at the point of waste generation for each untreated process wastewater stream plus the annual benzene quantity exiting the treatment process for each process wastewater stream treated in accordance with the requirements of paragraph (c)(1)(i) of this section.

(ii) Each treated process wastewater stream identified in paragraph (d)(2)(i) of this section shall be managed and treated in accordance with paragraph (c)(1) of this section.

(iii) Each untreated process wastewater stream identified in paragraph (d)(2)(i) of this section is exempt from the requirements of paragraph (c)(1) of this section.

(e) As an alternative to the requirements specified in paragraphs (c) and (d) of this section, an owner or operator of a facility at which the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr) as determined in paragraph (a) of this section may elect to manage and treat the facility waste as follows:

(1) The owner or operator shall manage and treat facility waste with a flow-weighted annual average water content of less than 10 percent in accordance with the requirements of paragraph (c)(1) of this section; and

(2) The owner or operator shall manage and treat facility waste (including remediation and process unit turnaround waste) with a flow-weighted annual average water content of 10 percent or greater, on a volume basis as total water, and each waste stream that is mixed with water or wastes at any time such that the resulting mixture has an annual water content greater than 10 percent, in accordance with the following:

(i) The benzene quantity for the wastes described in paragraph (e)(2) of this section must be equal to or less than 6.0 Mg/yr (6.6 ton/yr), as determined in § 61.355(k). Wastes as described in paragraph (e)(2) of this section that are transferred offsite shall be included in the determination of benzene quantity

as provided in § 61.355(k). The provisions of paragraph (f) of this section shall not apply to any owner or operator who elects to comply with the provisions of paragraph (e) of this section.

(ii) The determination of benzene quantity for each waste stream defined in paragraph (e)(2) of this section shall be made in accordance with § 61.355(k).

(f) Rather than treating the waste onsite, an owner or operator may elect to comply with paragraph (c)(1)(i) of this section by transferring the waste offsite to another facility where the waste is treated in accordance with the requirements of paragraph (c)(1)(i) of this section. The owner or operator transferring the waste shall:

(1) Comply with the standards specified in §§ 61.343 through 61.347 of this subpart for each waste management unit that receives or manages the waste prior to shipment of the waste offsite.

(2) Include with each offsite waste shipment a notice stating that the waste contains benzene which is required to be managed and treated in accordance with the provisions of this subpart.

(g) Compliance with this subpart will be determined by review of facility records and results from tests and inspections using methods and procedures specified in § 61.355 of this subpart.

(h) Permission to use an alternative means of compliance to meet the requirements of §§ 61.342 through 61.352 of this subpart may be granted by the Administrator as provided in § 61.353 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3095, Jan. 7, 1993; 65 FR 62159, 62160, Oct. 17, 2000]

#### **§ 61.343 Standards: Tanks.**

(a) Except as provided in paragraph (b) of this section and in § 61.351, the owner or operator must meet the standards in paragraph (a)(1) or (2) of this section for each tank in which the waste stream is placed in accordance with § 61.342 (c)(1)(ii). The standards in this section apply to the treatment and storage of the waste stream in a tank, including dewatering.

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the tank to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the tank except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the tank is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( 1 ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( 2 ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

( 3 ) The pressure is monitored continuously to ensure that the pressure in the tank remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(2) The owner or operator must install, operate, and maintain an enclosure and closed-vent system that routes all organic vapors vented from the tank, located inside the enclosure, to a control device in accordance with the requirements specified in paragraph (e) of this section.

(b) For a tank that meets all the conditions specified in paragraph (b)(1) of this section, the owner or operator may elect to comply with paragraph (b)(2) of this section as an alternative to the requirements specified in paragraph (a)(1) of this section.

(1) The waste managed in the tank complying with paragraph (b)(2) of this section shall meet all of the following conditions:

(i) Each waste stream managed in the tank must have a flow-weighted annual average water content less than or equal to 10 percent water, on a volume basis as total water.

(ii) The waste managed in the tank either:

(A) Has a maximum organic vapor pressure less than 5.2 kilopascals (kPa) (0.75 pounds per square inch (psi));

(B) Has a maximum organic vapor pressure less than 27.6 kPa (4.0 psi) and is managed in a tank having design capacity less than 151 m<sup>3</sup> (40,000 gal); or

(C) Has a maximum organic vapor pressure less than 76.6 kPa (11.1 psi) and is managed in a tank having a design capacity less than 75 m<sup>3</sup> (20,000 gal).

(2) The owner or operator shall install, operate, and maintain a fixed roof as specified in paragraph (a)(1)(i).

(3) For each tank complying with paragraph (b) of this section, one or more devices which vent directly to the atmosphere may be used on the tank provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the tank or cover resulting from filling or emptying the tank, diurnal temperature changes, atmospheric pressure changes or malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(c) Each fixed-roof, seal, access door, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access doors and other openings are closed and gasketed properly.



(d) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 45 calendar days after identification.

(e) Each owner or operator who controls air pollutant emissions by using an enclosure vented through a closed-vent system to a control device must meet the requirements specified in paragraphs (e)(1) through (4) of this section.

(1) The tank must be located inside a total enclosure. The enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of material into or out of the enclosure by conveyor, vehicles, or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of Procedure T initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the requirements for Tank Level 2 control requirements 40 CFR 264.1084(i) or 40 CFR 265(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(2) The enclosure must be vented through a closed-vent system to a control device that is designed and operated in accordance with the standards for control devices specified in § 61.349.

(3) Safety devices, as defined in this subpart, may be installed and operated as necessary on any enclosure, closed-vent system, or control device used to comply with the requirements of paragraphs (e)(1) and (2) of this section.

(4) The closed-vent system must be designed and operated in accordance with the requirements of § 61.349.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 18331, May 2, 1990; 58 FR 3096, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 6082, Feb. 6, 2003; 68 FR 67935, Dec. 4, 2003]

#### **§ 61.344 Standards: Surface impoundments.**

(a) The owner or operator shall meet the following standards for each surface impoundment in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each surface impoundment a cover (e.g., air-supported structure or rigid cover) and closed-vent system that routes all organic vapors vented from the surface impoundment to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the surface impoundment except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the enclosure of the surface impoundment is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( 1 ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( 2 ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart; and

( 3 ) The pressure is monitored continuously to ensure that the pressure in the enclosure of the surface impoundment remains below atmospheric pressure.

(D) The cover shall be used at all times that waste is placed in the surface impoundment except during removal of treatment residuals in accordance with 40 CFR 268.4 or closure of the surface impoundment in accordance with 40 CFR 264.228. (Note: the treatment residuals generated by these activities may be subject to the requirements of this part.)

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993]

#### **§ 61.345 Standards: Containers.**

(a) The owner or operator shall meet the following standards for each container in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a cover on each container used to handle, transfer, or store waste in accordance with the following requirements:

(i) The cover and all openings (e.g., bungs, hatches, and sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Except as provided in paragraph (a)(4) of this section, each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the container except when it is necessary to use the opening for waste loading, removal, inspection, or sampling.

(2) When a waste is transferred into a container by pumping, the owner or operator shall perform the transfer using a submerged fill pipe. The submerged fill pipe outlet shall extend to within two fill pipe diameters of the bottom of the container while the container is being loaded. During loading of the waste, the cover shall remain in place and all openings shall be maintained in a closed, sealed position except

for those openings required for the submerged fill pipe, those openings required for venting of the container to prevent physical damage or permanent deformation of the container or cover, and any openings complying with paragraph (a)(4) of this section.

(3) Treatment of a waste in a container, including aeration, thermal or other treatment, must be performed by the owner or operator in a manner such that while the waste is being treated the container meets the standards specified in paragraphs (a)(3)(i) through (iii) of this section, except for covers and closed-vent systems that meet the requirements in paragraph (a)(4) of this section.

(i) The owner or operator must either:

(A) Vent the container inside a total enclosure which is exhausted through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(A) and (B) of this section; or

(B) Vent the covered or closed container directly through a closed-vent system to a control device in accordance with the requirements of paragraphs (a)(3)(ii)(B) and (C) of this section.

(ii) The owner or operator must meet the following requirements, as applicable to the type of air emission control equipment selected by the owner or operator:

(A) The total enclosure must be designed and operated in accordance with the criteria for a permanent total enclosure as specified in section 5 of the "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B. The enclosure may have permanent or temporary openings to allow worker access; passage of containers through the enclosure by conveyor or other mechanical means; entry of permanent mechanical or electrical equipment; or direct airflow into the enclosure. The owner or operator must perform the verification procedure for the enclosure as specified in section 5.0 of "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" initially when the enclosure is first installed and, thereafter, annually. A facility that has conducted an initial compliance demonstration and that performs annual compliance demonstrations in accordance with the Container Level 3 control requirements in 40 CFR 264.1086(e)(2)(i) or 40 CFR 265.1086(e)(2)(i) is not required to make repeat demonstrations of initial and continuous compliance for the purposes of this subpart.

(B) The closed-vent system and control device must be designed and operated in accordance with the requirements of § 61.349.

(C) For a container cover, the cover and all openings ( e.g., doors, hatches) must be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h).

(iii) Safety devices, as defined in this subpart, may be installed and operated as necessary on any container, enclosure, closed-vent system, or control device used to comply with the requirements of paragraph (a)(3)(i) of this section.

(4) If the cover and closed-vent system operate such that the container is maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the container remains below atmospheric pressure.

(b) Each cover and all openings shall be visually inspected initially and quarterly thereafter to ensure that they are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3097, Jan. 7, 1993; 67 FR 68532, Nov. 12, 2002; 68 FR 67936, Dec. 4, 2003]

**§ 61.346 Standards: Individual drain systems.**

(a) Except as provided in paragraph (b) of this section, the owner or operator shall meet the following standards for each individual drain system in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain on each drain system opening a cover and closed-vent system that routes all organic vapors vented from the drain system to a control device.

(i) The cover shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the drain system except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the individual drain system is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( 1 ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( 2 ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

( 3 ) The pressure is monitored continuously to ensure that the pressure in the individual drain system remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with § 61.349 of this subpart.

(2) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur and that access hatches and other openings are closed and gasketed properly.

(3) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(b) As an alternative to complying with paragraph (a) of this section, an owner or operator may elect to comply with the following requirements:

(1) Each drain shall be equipped with water seal controls or a tightly sealed cap or plug.

(2) Each junction box shall be equipped with a cover and may have a vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

(i) Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

(ii) One of the following methods shall be used to control emissions from the junction box vent pipe to the atmosphere:

(A) Equip the junction box with a system to prevent the flow of organic vapors from the junction box vent pipe to the atmosphere during normal operation. An example of such a system includes use of water seal controls on the junction box. A flow indicator shall be installed, operated, and maintained on each junction box vent pipe to ensure that organic vapors are not vented from the junction box to the atmosphere during normal operation.

(B) Connect the junction box vent pipe to a closed-vent system and control device in accordance with § 61.349 of this subpart.

(3) Each sewer line shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

(4) Equipment installed in accordance with paragraphs (b)(1), (b)(2), or (b)(3) of this section shall be inspected as follows:

(i) Each drain using water seal controls shall be checked by visual or physical inspection initially and thereafter quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls.

(ii) Each drain using a tightly sealed cap or plug shall be visually inspected initially and thereafter quarterly to ensure caps or plugs are in place and properly installed.

(iii) Each junction box shall be visually inspected initially and thereafter quarterly to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

(iv) The unburied portion of each sewer line shall be visually inspected initially and thereafter quarterly for indication of cracks, gaps, or other problems that could result in benzene emissions.

(5) Except as provided in § 61.350 of this subpart, when a broken seal, gap, crack or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

**§ 61.347 Standards: Oil-water separators.**

(a) Except as provided in § 61.352 of this subpart, the owner or operator shall meet the following standards for each oil-water separator in which waste is placed in accordance with § 61.342(c)(1)(ii) of this subpart:

(1) The owner or operator shall install, operate, and maintain a fixed-roof and closed-vent system that routes all organic vapors vented from the oil-water separator to a control device.

(i) The fixed-roof shall meet the following requirements:

(A) The cover and all openings (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(B) Each opening shall be maintained in a closed, sealed position (e.g., covered by a lid that is gasketed and latched) at all times that waste is in the oil-water separator except when it is necessary to use the opening for waste sampling or removal, or for equipment inspection, maintenance, or repair.

(C) If the cover and closed-vent system operate such that the oil-water separator is maintained at a pressure less than atmospheric pressure, then paragraph (a)(1)(i)(B) of this section does not apply to any opening that meets all of the following conditions:

( 1 ) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

( 2 ) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

( 3 ) The pressure is monitored continuously to ensure that the pressure in the oil-water separator remains below atmospheric pressure.

(ii) The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 61.349 of this subpart.

(b) Each cover seal, access hatch, and all other openings shall be checked by visual inspection initially and quarterly thereafter to ensure that no cracks or gaps occur between the cover and oil-water separator wall and that access hatches and other openings are closed and gasketed properly.

(c) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, or when detectable emissions are measured, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3098, Jan. 7, 1993]

**§ 61.348 Standards: Treatment processes.**

(a) Except as provided in paragraph (a)(5) of this section, the owner or operator shall treat the waste stream in accordance with the following requirements:

(1) The owner or operator shall design, install, operate, and maintain a treatment process that either:

(i) Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

(ii) Removes benzene from the waste stream by 99 percent or more on a mass basis, or

(iii) Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

(2) Each treatment process complying with paragraphs (a)(1)(i) or (a)(1)(ii) of this section shall be designed and operated in accordance with the appropriate waste management unit standards specified in §§ 61.343 through 61.347 of this subpart. For example, if a treatment process is a tank, then the owner or operator shall comply with § 61.343 of this subpart.

(3) For the purpose of complying with the requirements specified in paragraph (a)(1)(i) of this section, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

(4) An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph (a)(1) of this section except as provided in paragraph (a)(5) of this section.

(5) If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to § 61.342(c)(1) of this subpart together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of this section. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

(b) Except for facilities complying with § 61.342(e), the owner or operator that aggregates or mixes individual waste streams as defined in paragraph (a)(5) of this section for management and treatment in a wastewater treatment system shall comply with the following requirements:

(1) The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in §§ 61.343 through 61.347 of this subpart.

(2) The provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

(i) The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in § 61.355(c) of this subpart; and

(ii) The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(A) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management

unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(B) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

(c) The owner and operator shall demonstrate that each treatment process or wastewater treatment system unit, except as provided in paragraph (d) of this section, achieves the appropriate conditions specified in paragraphs (a) or (b) of this section in accordance with the following requirements:

(1) Engineering calculations in accordance with requirements specified in § 61.356(e) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) A treatment process or waste stream is in compliance with the requirements of this subpart and exempt from the requirements of paragraph (c) of this section provided that the owner or operator documents that the treatment process or waste stream is in compliance with other regulatory requirements as follows:

(1) The treatment process is a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O;

(2) The treatment process is an industrial furnace or boiler burning hazardous waste for energy recovery for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart D;

(3) The waste stream is treated by a means or to a level that meets benzene-specific treatment standards in accordance with the Land Disposal Restrictions under 40 CFR part 268, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart;

(4) The waste stream is treated by a means or to a level that meets benzene-specific effluent limitations or performance standards in accordance with the Effluent Guidelines and Standards under 40 CFR parts 401-464, and the treatment process is designed and operated with a closed-vent system and control device meeting the requirements of § 61.349 of this subpart; or

(5) The waste stream is discharged to an underground injection well for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 122.

(e) Except as specified in paragraph (e)(3) of this section, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.



(1) Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

(2) Except as provided in § 61.350 of this subpart, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

(3) If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

(i) The purpose of the opening is to provide dilution air to reduce the explosion hazard;

(ii) The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h); and

(iii) The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.

(f) Except for treatment processes complying with paragraph (d) of this section, the Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in paragraphs (a) or (b) of this section by conducting a performance test using the test methods and procedures as required in § 61.355 of this subpart.

(g) The owner or operator of a treatment process or wastewater treatment system unit that is used to comply with the provisions of this section shall monitor the unit in accordance with the applicable requirements in § 61.354 of this subpart.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

#### **§ 61.349 Standards: Closed-vent systems and control devices.**

(a) For each closed-vent system and control device used to comply with standards in accordance with §§ 61.343 through 61.348 of this subpart, the owner or operator shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

(1) The closed-vent system shall:

(i) Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in § 61.355(h) of this subpart.

(ii) Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in paragraph (a)(1)(ii)(B) of this section.

(A) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

(B) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

(iii) All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(iv) For each closed-vent system complying with paragraph (a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

(2) The control device shall be designed and operated in accordance with the following conditions:

(i) An enclosed combustion device (e.g., a vapor incinerator, boiler, or process heater) shall meet one of the following conditions:

(A) Reduce the organic emissions vented to it by 95 weight percent or greater;

(B) Achieve a total organic compound concentration of 20 ppmv (as the sum of the concentrations for individual compounds using Method 18) on a dry basis corrected to 3 percent oxygen; or

(C) Provide a minimum residence time of 0.5 seconds at a minimum temperature of 760 °C (1,400 °F). If a boiler or process heater issued as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery system (e.g., a carbon adsorption system or a condenser) shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(iii) A flare shall comply with the requirements of 40 CFR 60.18.

(iv) A control device other than those described in paragraphs (a)(2) (i) through (iii) of this section may be used provided that the following conditions are met:

(A) The device shall recover or control the organic emissions vented to it with an efficiency of 95 weight percent or greater, or shall recover or control the benzene emissions vented to it with an efficiency of 98 weight percent or greater.

(B) The owner or operator shall develop test data and design information that documents the control device will achieve an emission control efficiency of either 95 percent or greater for organic compounds or 98 percent or greater for benzene.

(C) The owner or operator shall identify:

( 1 ) The critical operating parameters that affect the emission control performance of the device;

( 2 ) The range of values of these operating parameters that ensure the emission control efficiency specified in paragraph (a)(2)(iv)(A) of this section is maintained during operation of the device; and

( 3 ) How these operating parameters will be monitored to ensure the proper operation and maintenance of the device.

(D) The owner or operator shall submit the information and data specified in paragraphs (a)(2)(iv)(B) and (C) of this section to the Administrator prior to operation of the alternative control device.

(E) The Administrator will determine, based on the information submitted under paragraph (a)(2)(iv)(D) of this section, if the control device subject to paragraph (a)(2)(iv) of this section meets the requirements of § 61.349. The control device subject to paragraph (a)(2)(iv) of this section may be operated prior to receiving approval from the Administrator. However, if the Administrator determines that the control device does not meet the requirements of § 61.349, the facility may be subject to enforcement action beginning from the time the control device began operation.

(b) Each closed-vent system and control device used to comply with this subpart shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.

(c) An owner and operator shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in paragraph (a)(2) of this section by using one of the following methods:

(1) Engineering calculations in accordance with requirements specified in § 61.356(f) of this subpart; or

(2) Performance tests conducted using the test methods and procedures that meet the requirements specified in § 61.355 of this subpart.

(d) An owner or operator shall demonstrate compliance of each flare in accordance with paragraph (a)(2)(iii) of this section.

(e) The Administrator may request at any time an owner or operator demonstrate that a control device meets the applicable conditions specified in paragraph (a)(2) of this section by conducting a performance test using the test methods and procedures as required in § 61.355, and for control devices subject to paragraph (a)(2)(iv) of this section, the Administrator may specify alternative test methods and procedures, as appropriate.

(f) Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections.

(g) Except as provided in § 61.350 of this subpart, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

(h) The owner or operator of a control device that is used to comply with the provisions of this section shall monitor the control device in accordance with § 61.354(c) of this subpart.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3098, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

**§ 61.350 Standards: Delay of repair.**

(a) Delay of repair of facilities or units that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial facility or unit shutdown.

(b) Repair of such equipment shall occur before the end of the next facility or unit shutdown.

**§ 61.351 Alternative standards for tanks.**

(a) As an alternative to the standards for tanks specified in § 61.343 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A fixed roof and internal floating roof meeting the requirements in 40 CFR 60.112b(a)(1);

(2) An external floating roof meeting the requirements of 40 CFR 60.112b (a)(2); or

(3) An alternative means of emission limitation as described in 40 CFR 60.114b.

(b) If an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions of § 61.343 of this subpart applicable to the same facilities.

[55 FR 8346, Mar. 7, 1990, as amended at 55 FR 37231, Sept. 10, 1990]

**§ 61.352 Alternative standards for oil-water separators.**

(a) As an alternative to the standards for oil-water separators specified in § 61.347 of this subpart, an owner or operator may elect to comply with one of the following:

(1) A floating roof meeting the requirements in 40 CFR 60.693-2(a); or

(2) An alternative means of emission limitation as described in 40 CFR 60.694.

(b) For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, a fixed roof vented to a vapor control device that meets the requirements in §§ 61.347 and 61.349 of this subpart shall be installed and operated.

(c) Except as provided in paragraph (b) of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator is exempt from the provisions in § 61.347 of this subpart applicable to the same facilities.

**§ 61.353 Alternative means of emission limitation.**

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in benzene emissions at least equivalent to the reduction in benzene emissions from the source achieved by the applicable design, equipment, work practice, or operational requirements in §§ 61.342 through 61.349, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section shall be published only after public notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall collect, verify, and submit to the Administrator information showing that the alternative means achieves equivalent emission reductions.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993]

#### **§ 61.354 Monitoring of operations.**

(a) Except for a treatment process or waste stream complying with § 61.348(d), the owner or operator shall monitor each treatment process or wastewater treatment system unit to ensure the unit is properly operated and maintained by one of the following monitoring procedures:

(1) Measure the benzene concentration of the waste stream exiting the treatment process complying with § 61.348(a)(1)(i) at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) Install, calibrate, operate, and maintain according to manufacturer's specifications equipment to continuously monitor and record a process parameter (or parameters) for the treatment process or wastewater treatment system unit that indicates proper system operation. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the unit is operating properly.

(b) If an owner or operator complies with the requirements of § 61.348(b), then the owner or operator shall monitor each wastewater treatment system to ensure the unit is properly operated and maintained by the appropriate monitoring procedure as follows:

(1) For the first exempt waste management unit in each waste treatment train, other than an enhanced biodegradation unit, measure the flow rate, using the procedures of § 61.355(b), and the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(2) For each enhanced biodegradation unit that is the first exempt waste management unit in a treatment train, measure the benzene concentration of each waste stream entering the unit at least once per month by collecting and analyzing one or more samples using the procedures specified in § 61.355(c)(3).

(c) An owner or operator subject to the requirements in § 61.349 of this subpart shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device to continuously monitor the control device operation as specified in the following paragraphs, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator. The owner or operator shall inspect at least once each operating day the data recorded by the monitoring equipment (e.g., temperature monitor or flow indicator) to ensure that the control device is operating properly.

(1) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of  $\pm 1$  percent of the temperature being monitored in  $^{\circ}\text{C}$  or  $\pm 0.5$   $^{\circ}\text{C}$ , whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(2) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of  $\pm 1$  percent of the temperature being monitored in  $^{\circ}\text{C}$  or  $\pm 0.5$   $^{\circ}\text{C}$ , whichever is greater. One temperature

sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(3) For a flare, a monitoring device in accordance with 40 CFR 60.18(f)(2) equipped with a continuous recorder.

(4) For a boiler or process heater having a design heat input capacity less than 44 MW ( $150 \times 10^6$  BTU/hr), a temperature monitoring device equipped with a continuous recorder. The device shall have an accuracy of  $\pm 1$  percent of the temperature being monitored in  $^{\circ}\text{C}$  or  $\pm 0.5$   $^{\circ}\text{C}$ , whichever is greater. The temperature sensor shall be installed at a representative location in the combustion chamber.

(5) For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW ( $150 \times 10^6$  BTU/hr), a monitoring device equipped with a continuous recorder to measure a parameter(s) that indicates good combustion operating practices are being used.

(6) For a condenser, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the condenser; or

(ii) A temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations, and have an accuracy of  $\pm 1$  percent of the temperature being monitored in  $^{\circ}\text{C}$  or  $\pm 0.5$   $^{\circ}\text{C}$ , whichever is greater. One temperature sensor shall be installed at a location in the exhaust stream from the condenser, and a second temperature sensor shall be installed at a location in the coolant fluid exiting the condenser.

(7) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(i) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(ii) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(8) For a vapor recovery system other than a condenser or carbon adsorption system, a monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the control device.

(9) For a control device subject to the requirements of § 61.349(a)(2)(iv), devices to monitor the parameters as specified in § 61.349(a)(2)(iv)(C).

(d) For a carbon adsorption system that does not regenerate the carbon bed directly on site in the control device (e.g., a carbon canister), either the concentration level of the organic compounds or the concentration level of benzene in the exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon

replacement interval that is determined by the maximum design flow rate and either the organic concentration or the benzene concentration in the gas stream vented to the carbon adsorption system.

(e) An alternative operation or process parameter may be monitored if it can be demonstrated that another parameter will ensure that the control device is operated in conformance with these standards and the control device's design specifications.

(f) Owners or operators using a closed-vent system that contains any bypass line that could divert a vent stream from a control device used to comply with the provisions of this subpart shall do the following:

(1) Visually inspect the bypass line valve at least once every month, checking the position of the valve and the condition of the car-seal or closure mechanism required under § 61.349(a)(1)(ii) to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) Visually inspect the readings from each flow monitoring device required by § 61.349(a)(1)(ii) at least once each operating day to check that vapors are being routed to the control device as required.

(g) Each owner or operator who uses a system for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air shall install, calibrate, maintain, and operate according to the manufacturer's specifications a device equipped with a continuous recorder to monitor the pressure in the unit to ensure that it is less than atmospheric pressure.

[55 FR 8346, Mar. 7, 1990, as amended at 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

#### **§ 61.355 Test methods, procedures, and compliance provisions.**

(a) An owner or operator shall determine the total annual benzene quantity from facility waste by the following procedure:

(1) For each waste stream subject to this subpart having a flow-weighted annual average water content greater than 10 percent water, on a volume basis as total water, or is mixed with water or other wastes at any time and the resulting mixture has an annual average water content greater than 10 percent as specified in § 61.342(a), the owner or operator shall:

(i) Determine the annual waste quantity for each waste stream using the procedures specified in paragraph (b) of this section.

(ii) Determine the flow-weighted annual average benzene concentration for each waste stream using the procedures specified in paragraph (c) of this section.

(iii) Calculate the annual benzene quantity for each waste stream by multiplying the annual waste quantity of the waste stream times the flow-weighted annual average benzene concentration.

(2) Total annual benzene quantity from facility waste is calculated by adding together the annual benzene quantity for each waste stream generated during the year and the annual benzene quantity for each process unit turnaround waste annualized according to paragraph (b)(4) of this section.

(3) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall comply with the requirements of § 61.342 (c), (d), or (e).

(4) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

(5) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

(i) Comply with the recordkeeping requirements of § 61.356 and reporting requirements of § 61.357 of this subpart; and

(ii) Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(6) The benzene quantity in a waste stream that is generated less than one time per year, except as provided for process unit turnaround waste in paragraph (b)(4) of this section, shall be included in the determination of total annual benzene quantity from facility waste for the year in which the waste is generated unless the waste stream is otherwise excluded from the determination of total annual benzene quantity from facility waste in accordance with paragraphs (a) through (c) of this section. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste, for purposes of determining the total annual benzene quantity from facility waste.

(b) For purposes of the calculation required by paragraph (a) of this section, an owner or operator shall determine the annual waste quantity at the point of waste generation, unless otherwise provided in paragraphs (b) (1), (2), (3), and (4) of this section, by one of the methods given in paragraphs (b) (5) through (7) of this section.

(1) The determination of annual waste quantity for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(2) The determination of annual waste quantity for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

(i) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

(ii) The ammonia still meets the definition of a sour water stripper in § 61.341.

(3) The determination of annual waste quantity for wastes that are received at hazardous waste treatment, storage, or disposal facilities from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.



(4) The determination of annual waste quantity for each process unit turnaround waste generated only at 2 year or greater intervals, may be made by dividing the total quantity of waste generated during the most recent process unit turnaround by the time period (in the nearest tenth of a year) between the turnaround resulting in generation of the waste and the most recent preceding process turnaround for the unit. The resulting annual waste quantity shall be included in the calculation of the annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in which the turnaround occurs and for each subsequent year until the unit undergoes the next process turnaround. For estimates of total annual benzene quantity as specified in the 90-day report, required under § 61.357(a)(1), the owner or operator shall estimate the waste quantity generated during the most recent turnaround, and the time period between turnarounds in accordance with good engineering practices. If the owner or operator chooses not to annualize process unit turnaround waste, as specified in this paragraph, then the process unit turnaround waste quantity shall be included in the calculation of the annual benzene quantity for the year in which the turnaround occurs.

(5) Select the highest annual quantity of waste managed from historical records representing the most recent 5 years of operation or, if the facility has been in service for less than 5 years but at least 1 year, from historical records representing the total operating life of the facility;

(6) Use the maximum design capacity of the waste management unit; or

(7) Use measurements that are representative of maximum waste generation rates.

(c) For the purposes of the calculation required by §§ 61.355(a) of this subpart, an owner or operator shall determine the flow-weighted annual average benzene concentration in a manner that meets the requirements given in paragraph (c)(1) of this section using either of the methods given in paragraphs (c)(2) and (c)(3) of this section.

(1) The determination of flow-weighted annual average benzene concentration shall meet all of the following criteria:

(i) The determination shall be made at the point of waste generation except for the specific cases given in paragraphs (c)(1)(i)(A) through (D) of this section.

(A) The determination for sour water streams that are processed in sour water strippers shall be made at the point that the water exits the sour water stripper.

(B) The determination for wastes at coke by-product plants subject to and complying with the control requirements of § 61.132, 61.133, 61.134, or 61.139 of subpart L of this part shall be made at the location that the waste stream exits the process unit component or waste management unit controlled by that subpart or at the exit of the ammonia still, provided that the following conditions are met:

( 1 ) The transfer of wastes between units complying with the control requirements of subpart L of this part, process units, and the ammonia still is made through hard piping or other enclosed system.

( 2 ) The ammonia still meets the definition of a sour water stripper in § 61.341.

(C) The determination for wastes that are received from offsite shall be made at the point where the waste enters the hazardous waste treatment, storage, or disposal facility.

(D) The determination of flow-weighted annual average benzene concentration for process unit turnaround waste shall be made using either of the methods given in paragraph (c)(2) or (c)(3) of this section. The resulting flow-weighted annual average benzene concentration shall be included in the calculation of annual benzene quantity as provided in paragraph (a)(1)(iii) of this section for the year in

which the turnaround occurs and for each subsequent year until the unit undergoes the next process unit turnaround.

(ii) Volatilization of the benzene by exposure to air shall not be used in the determination to reduce the benzene concentration.

(iii) Mixing or diluting the waste stream with other wastes or other materials shall not be used in the determination—to reduce the benzene concentration.

(iv) The determination shall be made prior to any treatment of the waste that removes benzene, except as specified in paragraphs (c)(1)(i)(A) through (D) of this section.

(v) For wastes with multiple phases, the determination shall provide the weighted-average benzene concentration based on the benzene concentration in each phase of the waste and the relative proportion of the phases.

(2) *Knowledge of the waste.* The owner or operator shall provide sufficient information to document the flow-weighted annual average benzene concentration of each waste stream. Examples of information that could constitute knowledge include material balances, records of chemicals purchases, or previous test results provided the results are still relevant to the current waste stream conditions. If test data are used, then the owner or operator shall provide documentation describing the testing protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the flow-weighted annual average benzene concentration for the waste stream. When an owner or operator and the Administrator do not agree on determinations of the flow-weighted annual average benzene concentration based on knowledge of the waste, the procedures under paragraph (c)(3) of this section shall be used to resolve the disagreement.

(3) Measurements of the benzene concentration in the waste stream in accordance with the following procedures:

(i) Collect a minimum of three representative samples from each waste stream. Where feasible, samples shall be taken from an enclosed pipe prior to the waste being exposed to the atmosphere.

(ii) For waste in enclosed pipes, the following procedures shall be used:

(A) Samples shall be collected prior to the waste being exposed to the atmosphere in order to minimize the loss of benzene prior to sampling.

(B) A static mixer shall be installed in the process line or in a by-pass line unless the owner or operator demonstrates that installation of a static mixer in the line is not necessary to accurately determine the benzene concentration of the waste stream.

(C) The sampling tap shall be located within two pipe diameters of the static mixer outlet.

(D) Prior to the initiation of sampling, sample lines and cooling coil shall be purged with at least four volumes of waste.

(E) After purging, the sample flow shall be directed to a sample container and the tip of the sampling tube shall be kept below the surface of the waste during sampling to minimize contact with the atmosphere.

(F) Samples shall be collected at a flow rate such that the cooling coil is able to maintain a waste temperature less than 10 °C (50 °F).

(G) After filling, the sample container shall be capped immediately (within 5 seconds) to leave a minimum headspace in the container.

(H) The sample containers shall immediately be cooled and maintained at a temperature below 10 °C (50 °F) for transfer to the laboratory.

(iii) When sampling from an enclosed pipe is not feasible, a minimum of three representative samples shall be collected in a manner to minimize exposure of the sample to the atmosphere and loss of benzene prior to sampling.

(iv) Each waste sample shall be analyzed using one of the following test methods for determining the benzene concentration in a waste stream:

(A) Method 8020, Aromatic Volatile Organics, in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(B) Method 8021, Volatile Organic Compounds in Water by Purge and Trap Capillary Column Gas Chromatography with Photoionization and Electrolytic Conductivity Detectors in Series in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(C) Method 8240, Gas Chromatography/Mass Spectrometry for Volatile Organics in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(D) Method 8260, Gas Chromatography/Mass Spectrometry for Volatile Organics: Capillary Column Technique in "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication No. SW-846 (incorporation by reference as specified in § 61.18 of this part);

(E) Method 602, Purgeable Aromatics, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA methods; or

(F) Method 624, Purgeables, as described in 40 CFR part 136, appendix A, Test Procedures for Analysis of Organic Pollutants, for wastewaters for which this is an approved EPA method.

(v) The flow-weighted annual average benzene concentration shall be calculated by averaging the results of the sample analyses as follows:

$$\bar{C} = \frac{1}{Q_t} \times \sum_{i=1}^n (Q_i)(C_i)$$

Where:

$\bar{C}$  = Flow-weighted annual average benzene concentration for waste stream, ppmw.

$Q_t$  = Total annual waste quantity for waste stream, kg/yr (lb/yr).

$n$  = Number of waste samples (at least 3).

$Q_i$  = Annual waste quantity for waste stream represented by  $C_i$ , kg/yr (lb/yr).

$C_i$  = Measured concentration of benzene in waste sample  $i$ , ppmw.

(d) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348 (a)(1)(i) shall measure the flow-weighted annual average benzene concentration of the waste stream exiting the treatment process by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(e) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(ii) of this subpart shall determine the percent reduction of benzene in the waste stream on a mass basis by the following procedure:

(1) The test shall be conducted under conditions that exist when the treatment process is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the treatment process ( $E_b$ ) shall be determined by computing the product of the flow rate of the waste stream entering the treatment process, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene entering the treatment process is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[ \sum_{i=1}^n V_i C_i \right]$$

Where:

$E_b$  = Mass flow rate of benzene entering the treatment process, kg/hr (lb/hr).

$K$  = Density of the waste stream, kg/m<sup>3</sup> (lb/ft<sup>3</sup>).

$V_i$  = Average volume flow rate of waste entering the treatment process during each run  $i$ , m<sup>3</sup>/hr (ft<sup>3</sup>/hr).

$C_i$  = Average concentration of benzene in the waste stream entering the treatment process during each run  $i$ , ppmw.

$n$  = Number of runs.

$10^6$  = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the treatment process ( $E_a$ ) shall be determined by computing the product of the flow rate of the waste stream exiting the treatment process, as determined

by the outlet flow meter or the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling and analytical procedures specified in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over the same 3-hour period at which the mass flow rate of benzene entering the treatment process is determined. The mass flow rate of benzene exiting the treatment process is calculated as follows:

$$E_a = \frac{K}{n \times 10^6} \left[ \sum_{i=1}^n V_i C_i \right]$$

Where:

$E_a$  = Mass flow rate of benzene exiting the treatment process, kg/hr (lb/hr).

$K$  = Density of the waste stream, kg/m<sup>3</sup> (lb/ft<sup>3</sup>).

$V_i$  = Average volume flow rate of waste exiting the treatment process during each run  $i$ , m<sup>3</sup>/hr (ft<sup>3</sup>/hr).

$C_i$  = Average concentration of benzene in the waste stream exiting the treatment process during each run  $i$ , ppmw.

$n$  = Number of runs.

$10^6$  = Conversion factor for ppmw.

(f) An owner or operator using performance tests to demonstrate compliance of a treatment process with § 61.348(a)(1)(iii) of this subpart shall determine the benzene destruction efficiency for the combustion unit by the following procedure:

(1) The test shall be conducted under conditions that exist when the combustion unit is operating at the highest inlet waste stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(3) The mass flow rate of benzene entering the combustion unit shall be determined by computing the product of the flow rate of the waste stream entering the combustion unit, as determined by the inlet flow meter, and the benzene concentration of the waste stream, as determined using the sampling procedures in paragraph (c)(2) or (c)(3) of this section. Three grab samples of the waste shall be taken at equally spaced time intervals over a 1-hour period. Each 1-hour period constitutes a run, and the performance test shall consist of a minimum of 3 runs conducted over a 3-hour period. The mass flow rate of benzene into the combustion unit is calculated as follows:

$$E_b = \frac{K}{n \times 10^6} \left[ \sum_{i=1}^n V_i C_i \right]$$

Where:

$E_b$  = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

$K$  = Density of the waste stream, kg/m<sup>3</sup> (lb/ft<sup>3</sup>).

$V_i$  = Average volume flow rate of waste entering the combustion unit during each run  $i$ , m<sup>3</sup>/hr (ft<sup>3</sup>/hr).

$C_i$  = Average concentration of benzene in the waste stream entering the combustion unit during each run  $i$ , ppmw.

$n$  = Number of runs.

$10^6$  = Conversion factor for ppmw.

(4) The mass flow rate of benzene exiting the combustion unit exhaust stack shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected and be the same time period at which the mass flow rate of benzene entering the treatment process is determined. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample and each 1-hour period shall correspond to the periods when the waste feed is sampled.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate.

(C) The average benzene concentration in the exhaust downstream of the combustion unit shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of benzene emitted during each run shall be calculated as follows:

$$M_i = D_b V C (10^{-6})$$

Where:

$M_i$  = Mass of benzene emitted during run  $i$ , kg (lb).

$V$  = Volume of air-vapor mixture exhausted at standard conditions, m<sup>3</sup> (ft<sup>3</sup>).

$C$  = Concentration of benzene measured in the exhaust, ppmv.

$D_b$  = Density of benzene, 3.24 kg/m<sup>3</sup> (0.202 lb/ft<sup>3</sup>).

$10^6$  = Conversion factor for ppmv.

(iv) The benzene mass emission rate in the exhaust shall be calculated as follows:

$$E_a = \left( \sum_{i=1}^n M_i \right) / T$$

Where:

$E_a$  = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

$M_i$  = Mass of benzene emitted from the combustion unit during run i, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(5) The benzene destruction efficiency for the combustion unit shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Benzene destruction efficiency for the combustion unit, percent.

$E_b$  = Mass flow rate of benzene entering the combustion unit, kg/hr (lb/hr).

$E_a$  = Mass flow rate of benzene emitted from the combustion unit, kg/hr (lb/hr).

(g) An owner or operator using performance tests to demonstrate compliance of a wastewater treatment system unit with § 61.348(b) shall measure the flow-weighted annual average benzene concentration of the wastewater stream where the waste stream enters an exempt waste management unit by collecting and analyzing a minimum of three representative samples of the waste stream using the procedures in paragraph (c)(3) of this section. The test shall be conducted under conditions that exist when the wastewater treatment system is operating at the highest inlet wastewater stream flow rate and benzene content expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information as is necessary to document the operating conditions during the test.

(h) An owner or operator shall test equipment for compliance with no detectable emissions as required in §§ 61.343 through 61.347, and § 61.349 of this subpart in accordance with the following requirements:

(1) Monitoring shall comply with Method 21 from appendix A of 40 CFR part 60.

(2) The detection instrument shall meet the performance criteria of Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The background level shall be determined as set forth in Method 21.

(6) The instrument probe shall be traversed around all potential leak interfaces as close as possible to the interface as described in Method 21.

(7) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared to 500 ppm for determining compliance.

(i) An owner or operator using a performance test to demonstrate compliance of a control device with either the organic reduction efficiency requirement or the benzene reduction efficiency requirement specified under § 61.349(a)(2) shall use the following procedures:

(1) The test shall be conducted under conditions that exist when the waste management unit vented to the control device is operating at the highest load or capacity level expected to occur. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a test. The owner or operator shall record all process information necessary to document the operating conditions during the test.

(2) Sampling sites shall be selected using Method 1 or 1A from appendix A of 40 CFR part 60, as appropriate.

(3) The mass flow rate of either the organics or benzene entering and exiting the control device shall be determined as follows:

(i) The time period for the test shall not be less than 3 hours during which at least 3 stack gas samples are collected. Samples of the vent stream entering and exiting the control device shall be collected during the same time period. Each sample shall be collected over a 1-hour period (e.g., in a tedlar bag) to represent a time-integrated composite sample.

(ii) A run shall consist of a 1-hour period during the test. For each run:

(A) The reading from each measurement shall be recorded;

(B) The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D from appendix A of 40 CFR part 60, as appropriate;

(C) The organic concentration or the benzene concentration, as appropriate, in the vent stream entering and exiting the control shall be determined using Method 18 from appendix A of 40 CFR part 60.

(iii) The mass of organics or benzene entering and exiting the control device during each run shall be calculated as follows:

$$M_{aj} = \frac{K_i V_{aj}}{10^6} \left( \sum_{i=1}^n C_{ai} MW_i \right) \quad M_{bj} = \frac{K_i V_{bj}}{10^6} \left( \sum_{i=1}^n C_{bi} MW_i \right)$$

$M_{aj}$  = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

$M_{bj}$  = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

$V_{aj}$  = Volume of vent stream entering the control device during run j, at standard conditions,  $m^3$  ( $ft^3$ ).

$V_{bj}$  = Volume of vent stream exiting the control device during run j, at standard conditions,  $m^3$  ( $ft^3$ ).



$C_{ai}$  = Organic concentration of compound i or the benzene concentration measured in the vent stream entering the control device as determined by Method 18, ppm by volume on a dry basis.

$C_{bi}$  = Organic concentration of compound i or the benzene concentration measured in the vent stream exiting the control device as determined by Method 18, ppm by volume on a dry basis.

$MW_i$  = Molecular weight of organic compound i in the vent stream, or the molecular weight of benzene, kg/kg-mol (lb/lb-mole).

n = Number of organic compounds in the vent stream; if benzene reduction efficiency is being demonstrated, then n=1.

$K_1$  = Conversion factor for molar volume at standard conditions (293 K and 760 mm Hg (527 R and 14.7 psia))

$$= 0.0416 \text{ kg-mol/m}^3 \text{ (0.00118 lb-mol/ft}^3 \text{)}$$

$10^{-6}$  = Conversion factor for ppmv.

(iv) The mass flow rate of organics or benzene entering and exiting the control device shall be calculated as follows:

$$E_a = \left( \sum_{j=1}^n M_{aj} \right) / T$$

$$E_b = \left( \sum_{j=1}^n M_{bj} \right) / T$$

Where:

$E_a$  = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

$E_b$  = Mass flow rate of organics or benzene exiting the control device, kg/hr (lb/hr).

$M_{aj}$  = Mass of organics or benzene in the vent stream entering the control device during run j, kg (lb).

$M_{bj}$  = Mass of organics or benzene in the vent stream exiting the control device during run j, kg (lb).

T = Total time of all runs, hr.

n = Number of runs.

(4) The organic reduction efficiency or the benzene reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_a - E_b}{E_a} \times 100$$

Where:

R = Total organic reduction of efficiency or benzene reduction efficiency for the control device, percent.

$E_b$  = Mass flow rate of organics or benzene entering the control device, kg/hr (lb/hr).

$E_a$  = Mass flow rate of organic or benzene emitted from the control device, kg/hr (lb/hr).

(j) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342 (c)(3)(ii)(B) according to the provisions of paragraph (a) of this section, except that the procedures in paragraph (a) of this section shall also apply to wastes with a water content of 10 percent or less.

(k) An owner or operator shall determine the benzene quantity for the purposes of the calculation required by § 61.342(e)(2) by the following procedure:

(1) For each waste stream that is not controlled for air emissions in accordance with § 61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the benzene quantity shall be determined as specified in paragraph (a) of this section, except that paragraph (b)(4) of this section shall not apply, i.e., the waste quantity for process unit turnaround waste is not annualized but shall be included in the determination of benzene quantity for the year in which the waste is generated for the purposes of the calculation required by § 61.342(e)(2).

(2) For each waste stream that is controlled for air emissions in accordance with § 61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), as applicable to the waste management unit that manages the waste, the determination of annual waste quantity and flow-weighted annual average benzene concentration shall be made at the first applicable location as described in paragraphs (k)(2)(i), (k)(2)(ii), and (k)(2)(iii) of this section and prior to any reduction of benzene concentration through volatilization of the benzene, using the methods given in (k)(2)(iv) and (k)(2)(v) of this section.

(i) Where the waste stream enters the first waste management unit not complying with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a) that are applicable to the waste management unit,

(ii) For each waste stream that is managed or treated only in compliance with §§ 61.343 through 61.348(a) up to the point of final direct discharge from the facility, the determination of benzene quantity shall be prior to any reduction of benzene concentration through volatilization of the benzene, or

(iii) For wastes managed in units controlled for air emissions in accordance with §§ 61.343, 61.344, 61.345, 61.346, 61.347, and 61.348(a), and then transferred offsite, facilities shall use the first applicable offsite location as described in paragraphs (k)(2)(i) and (k)(2)(ii) of this section if they have documentation from the offsite facility of the benzene quantity at this location. Facilities without this documentation for offsite wastes shall use the benzene quantity determined at the point where the transferred waste leaves the facility.

(iv) Annual waste quantity shall be determined using the procedures in paragraphs (b)(5), (6), or (7) of this section, and

(v) The flow-weighted annual average benzene concentration shall be determined using the procedures in paragraphs (c)(2) or (3) of this section.

(3) The benzene quantity in a waste stream that is generated less than one time per year, including process unit turnaround waste, shall be included in the determination of benzene quantity as determined in paragraph (k)(6) of this section for the year in which the waste is generated. The benzene quantity in this waste stream shall not be annualized or averaged over the time interval between the activities that resulted in generation of the waste for purposes of determining benzene quantity as determined in paragraph (k)(6) of this section.

(4) The benzene in waste entering an enhanced biodegradation unit, as defined in § 61.348(b)(2)(ii)(B), shall not be included in the determination of benzene quantity, determined in paragraph (k)(6) of this section, if the following conditions are met:

(i) The benzene concentration for each waste stream entering the enhanced biodegradation unit is less than 10 ppmw on a flow-weighted annual average basis, and

(ii) All prior waste management units managing the waste comply with §§ 61.343, 61.344, 61.345, 61.346, 61.347 and 61.348(a).

(5) The benzene quantity for each waste stream in paragraph (k)(2) of this section shall be determined by multiplying the annual waste quantity of each waste stream times its flow-weighted annual average benzene concentration.

(6) The total benzene quantity for the purposes of the calculation required by § 61.342(e)(2) shall be determined by adding together the benzene quantities determined in paragraphs (k)(1) and (k)(5) of this section for each applicable waste stream.

(7) If the benzene quantity determined in paragraph (6) of this section exceeds 6.0 Mg/yr (6.6 ton/yr) only because of multiple counting of the benzene quantity for a waste stream, the owner or operator may use the following procedures for the purposes of the calculation required by § 61.342(e)(2):

(i) Determine which waste management units are involved in the multiple counting of benzene;

(ii) Determine the quantity of benzene that is emitted, recovered, or removed from the affected units identified in paragraph (k)(7)(i) of this section, or destroyed in the units if applicable, using either direct measurements or the best available estimation techniques developed or approved by the Administrator.

(iii) Adjust the benzene quantity to eliminate the multiple counting of benzene based on the results from paragraph (k)(7)(ii) of this section and determine the total benzene quantity for the purposes of the calculation required by § 61.342(e)(2).

(iv) Submit in the annual report required under § 61.357(a) a description of the methods used and the resulting calculations for the alternative procedure under paragraph (k)(7) of this section, the benzene quantity determination from paragraph (k)(6) of this section, and the adjusted benzene quantity determination from paragraph (k)(7)(iii) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3099, Jan. 7, 1993; 65 FR 62160, Oct. 17, 2000]

#### **§ 61.356 Recordkeeping requirements.**

(a) Each owner or operator of a facility subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified.

(b) Each owner or operator shall maintain records that identify each waste stream at the facility subject to this subpart, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records:

(1) For each waste stream not controlled for benzene emissions in accordance with this subpart, the records shall include all test results, measurements, calculations, and other documentation used to

determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(2) For each waste stream exempt from § 61.342(c)(1) in accordance with § 61.342(c)(3), the records shall include:

(i) All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with § 61.342(c)(3)(i), or

(ii) All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with § 61.342(c)(3)(ii).

(3) For each facility where process wastewater streams are controlled for benzene emissions in accordance with § 61.342(d) of this subpart, the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

(4) For each facility where waste streams are controlled for benzene emissions in accordance with § 61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

(5) For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with § 61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with § 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with § 61.355(a)(1)(iii) of this section.

(6) For each facility where wastewater streams are controlled for benzene emissions in accordance with § 61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

(c) An owner or operator transferring waste off-site to another facility for treatment in accordance with § 61.342(f) shall maintain documentation for each offsite waste shipment that includes the following information: Date waste is shipped offsite, quantity of waste shipped offsite, name and address of the facility receiving the waste, and a copy of the notice sent with the waste shipment.

(d) An owner or operator using control equipment in accordance with §§ 61.343 through 61.347 shall maintain engineering design documentation for all control equipment that is installed on the waste management unit. The documentation shall be retained for the life of the control equipment. If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(e) An owner or operator using a treatment process or wastewater treatment system unit in accordance with § 61.348 of this subpart shall maintain the following records. The documentation shall be retained for the life of the unit.

(1) A statement signed and dated by the owner or operator certifying that the unit is designed to operate at the documented performance level when the waste stream entering the unit is at the highest waste stream flow rate and benzene content expected to occur.

(2) If engineering calculations are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain the complete design analysis for the unit. The design analysis shall include for example the following information: Design specifications, drawings, schematics, piping and instrumentation diagrams, and other documentation necessary to demonstrate the unit performance.

(3) If performance tests are used to determine treatment process or wastewater treatment system unit performance, then the owner or operator shall maintain all test information necessary to demonstrate the unit performance.

(i) A description of the unit including the following information: type of treatment process; manufacturer name and model number; and for each waste stream entering and exiting the unit, the waste stream type (e.g., process wastewater, sludge, slurry, etc.), and the design flow rate and benzene content.

(ii) Documentation describing the test protocol and the means by which sampling variability and analytical variability were accounted for in the determination of the unit performance. The description of the test protocol shall include the following information: sampling locations, sampling method, sampling frequency, and analytical procedures used for sample analysis.

(iii) Records of unit operating conditions during each test run including all key process parameters.

(iv) All test results.

(4) If a control device is used, then the owner or operator shall maintain the control device records required by paragraph (f) of this section.

(f) An owner or operator using a closed-vent system and control device in accordance with § 61.349 of this subpart shall maintain the following records. The documentation shall be retained for the life of the control device.

(1) A statement signed and dated by the owner or operator certifying that the closed-vent system and control device is designed to operate at the documented performance level when the waste management unit vented to the control device is or would be operating at the highest load or capacity expected to occur.

(2) If engineering calculations are used to determine control device performance in accordance with § 61.349(c), then a design analysis for the control device that includes for example:

(i) Specifications, drawings, schematics, and piping and instrumentation diagrams prepared by the owner or operator, or the control device manufacturer or vendor that describe the control device design based on acceptable engineering texts. The design analysis shall address the following vent stream characteristics and control device operating parameters:

(A) For a thermal vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperature in the combustion zone and the combustion zone residence time.

(B) For a catalytic vapor incinerator, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average temperatures across the catalyst bed inlet and outlet.

(C) For a boiler or process heater, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also establish the design minimum and average flame zone temperatures, combustion zone residence time, and description of method and location where the vent stream is introduced into the flame zone.

(D) For a flare, the design analysis shall consider the vent stream composition, constituent concentrations, and flow rate. The design analysis shall also consider the requirements specified in 40 CFR 60.18.

(E) For a condenser, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design outlet organic compound concentration level or the design outlet benzene concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(F) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, number and capacity of carbon beds, type and working capacity of activated carbon used for carbon beds, design total steam flow over the period of each complete carbon bed regeneration cycle, duration of the carbon bed steaming and cooling/drying cycles, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of carbon.

(G) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentration, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level or the design exhaust vent stream benzene concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device subject to the requirements of § 61.349(a)(2)(iv), the design analysis shall consider the vent stream composition, constituent concentration, and flow rate. The design analysis shall also include all of the information submitted under § 61.349 (a)(2)(iv).

(ii) [Reserved]

(3) If performance tests are used to determine control device performance in accordance with § 61.349(c) of this subpart:

(i) A description of how it is determined that the test is conducted when the waste management unit or treatment process is operating at the highest load or capacity level. This description shall include the

estimated or design flow rate and organic content of each vent stream and definition of the acceptable operating ranges of key process and control parameters during the test program.

(ii) A description of the control device including the type of control device, control device manufacturer's name and model number, control device dimensions, capacity, and construction materials.

(iii) A detailed description of sampling and monitoring procedures, including sampling and monitoring locations in the system, the equipment to be used, sampling and monitoring frequency, and planned analytical procedures for sample analysis.

(iv) All test results.

(g) An owner or operator shall maintain a record for each visual inspection required by §§ 61.343 through 61.347 of this subpart that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(h) An owner or operator shall maintain a record for each test of no detectable emissions required by §§ 61.343 through 61.347 and § 61.349 of this subpart. The record shall include the following information: date the test is performed, background level measured during test, and maximum concentration indicated by the instrument reading measured for each potential leak interface. If detectable emissions are measured at a leak interface, then the record shall also include the waste management unit, control equipment, and leak interface location where detectable emissions were measured, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed.

(i) For each treatment process and wastewater treatment system unit operated to comply with § 61.348, the owner or operator shall maintain documentation that includes the following information regarding the unit operation:

(1) Dates of startup and shutdown of the unit.

(2) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(a)(1) of this subpart, the owner or operator shall maintain records that include date each test is performed and all test results.

(3) If a process parameter is continuously monitored in accordance with § 61.354(a)(2) of this subpart, the owner or operator shall maintain records that include a description of the operating parameter (or parameters) to be monitored to ensure that the unit will be operated in conformance with these standards and the unit's design specifications, and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the unit.

(4) If measurements of waste stream benzene concentration are performed in accordance with § 61.354(b), the owner or operator shall maintain records that include the date each test is performed and all test results.

(5) Periods when the unit is not operated as designed.

(j) For each control device, the owner or operator shall maintain documentation that includes the following information regarding the control device operation:

(1) Dates of startup and shutdown of the closed-vent system and control device.

(2) A description of the operating parameter (or parameters) to be monitored to ensure that the control device will be operated in conformance with these standards and the control device's design specifications and an explanation of the criteria used for selection of that parameter (or parameters). This documentation shall be kept for the life of the control device.

(3) Periods when the closed-vent system and control device are not operated as designed including all periods and the duration when:

(i) Any valve car-seal or closure mechanism required under § 61.349(a)(1)(ii) is broken or the bypass line valve position has changed.

(ii) The flow monitoring devices required under § 61.349(a)(1)(ii) indicate that vapors are not routed to the control device as required.

(4) If a thermal vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the incinerator and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature.

(5) If a catalytic vapor incinerator is used, then the owner or operator shall maintain continuous records of the temperature of the gas stream both upstream and downstream of the catalyst bed of the incinerator, records of all 3-hour periods of operation during which the average temperature measured before the catalyst bed is more than 28 °C (50 °F) below the design gas stream temperature, and records of all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the design temperature difference.

(6) If a boiler or process heater is used, then the owner or operator shall maintain records of each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone as required by § 61.349(a)(2)(i)(C). For a boiler or process heater having a design heat input capacity less than 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the temperature of the gas stream in the combustion zone of the boiler or process heater and records of all 3-hour periods of operation during which the average temperature of the gas stream in the combustion zone is more than 28 °C (50 °F) below the design combustion zone temperature. For a boiler or process heater having a design heat input capacity greater than or equal to 44 MW (150 × 106 BTU/hr), the owner or operator shall maintain continuous records of the parameter(s) monitored in accordance with the requirements of § 61.354(c)(5).

(7) If a flare is used, then the owner or operator shall maintain continuous records of the flare pilot flame monitoring and records of all periods during which the pilot flame is absent.

(8) If a condenser is used, then the owner or operator shall maintain records from the monitoring device of the parameters selected to be monitored in accordance with § 61.354(c)(6). If concentration of organics or concentration of benzene in the control device outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the temperature of the condenser exhaust stream and coolant fluid is monitored, then the owner or operator shall record all 3-hour periods of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(9) If a carbon adsorber is used, then the owner or operator shall maintain records from the monitoring device of the concentration of organics or the concentration of benzene in the control device outlet gas stream. If the concentration of organics or the concentration of benzene in the control device



outlet gas stream is monitored, then the owner or operator shall record all 3-hour periods of operation during which the concentration of organics or the concentration of benzene in the exhaust stream is more than 20 percent greater than the design value. If the carbon bed regeneration interval is monitored, then the owner or operator shall record each occurrence when the vent stream continues to flow through the control device beyond the predetermined carbon bed regeneration time.

(10) If a carbon adsorber that is not regenerated directly on site in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time then the existing carbon in the control device is replaced with fresh carbon.

(11) If an alternative operational or process parameter is monitored for a control device, as allowed in § 61.354(e) of this subpart, then the owner or operator shall maintain records of the continuously monitored parameter, including periods when the device is not operated as designed.

(12) If a control device subject to the requirements of § 61.349(a)(2)(iv) is used, then the owner or operator shall maintain records of the parameters that are monitored and each occurrence when the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or other records as specified by the Administrator.

(k) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the recordkeeping requirements in 40 CFR 60.115b.

(l) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall maintain records of the following:

(1) The date, location, and corrective action for each visual inspection required by 40 CFR 60.693-2(a)(5), during which a broken seal, gap, or other problem is identified that could result in benzene emissions.

(2) Results of the seal gap measurements required by 40 CFR 60.693-2(a).

(m) If a system is used for emission control that is maintained at a pressure less than atmospheric pressure with openings to provide dilution air, then the owner or operator shall maintain records of the monitoring device and records of all periods during which the pressure in the unit is operated at a pressure that is equal to or greater than atmospheric pressure.

(n) Each owner or operator using a total enclosure to comply with control requirements for tanks in § 61.343 or the control requirements for containers in § 61.345 must keep the records required in paragraphs (n)(1) and (2) of this section. Owners or operators may use records as required in 40 CFR 264.1089(b)(2)(iv) or 40 CFR 265.1090(b)(2)(iv) for a tank or as required in 40 CFR 264.1089(d)(1) or 40 CFR 265.1090(d)(1) for a container to meet the recordkeeping requirement in paragraph (n)(1) of this section. The owner or operator must make the records of each verification of a total enclosure available for inspection upon request.

(1) Records of the most recent set of calculations and measurements performed to verify that the enclosure meets the criteria of a permanent total enclosure as specified in "Procedure T—Criteria for and Verification of a Permanent or Temporary Total Enclosure" in 40 CFR 52.741, appendix B;

(2) Records required for a closed-vent system and control device according to the requirements in paragraphs (d) (f), and (j) of this section.

[55 FR 8346, Mar. 7, 1990; 55 FR 12444, Apr. 3, 1990; 55 FR 18331, May 2, 1990, as amended at 58 FR 3103, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000; 67 FR 68533, Nov. 12, 2002]

**§ 61.357 Reporting requirements.**

(a) Each owner or operator of a chemical plant, petroleum refinery, coke by-product recovery plant, and any facility managing wastes from these industries shall submit to the Administrator within 90 days after January 7, 1993, or by the initial startup for a new source with an initial startup after the effective date, a report that summarizes the regulatory status of each waste stream subject to § 61.342 and is determined by the procedures specified in § 61.355(c) to contain benzene. Each owner or operator subject to this subpart who has no benzene onsite in wastes, products, by-products, or intermediates shall submit an initial report that is a statement to this effect. For all other owners or operators subject to this subpart, the report shall include the following information:

(1) Total annual benzene quantity from facility waste determined in accordance with § 61.355(a) of this subpart.

(2) A table identifying each waste stream and whether or not the waste stream will be controlled for benzene emissions in accordance with the requirements of this subpart.

(3) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart the following information shall be added to the table:

(i) Whether or not the water content of the waste stream is greater than 10 percent;

(ii) Whether or not the waste stream is a process wastewater stream, product tank drawdown, or landfill leachate;

(iii) Annual waste quantity for the waste stream;

(iv) Range of benzene concentrations for the waste stream;

(v) Annual average flow-weighted benzene concentration for the waste stream; and

(vi) Annual benzene quantity for the waste stream.

(4) The information required in paragraphs (a) (1), (2), and (3) of this section should represent the waste stream characteristics based on current configuration and operating conditions. An owner or operator only needs to list in the report those waste streams that contact materials containing benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in § 61.10(a).

(b) If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

(c) If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr)

or more. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(d) If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Administrator the following reports:

(1) Within 90 days after January 7, 1993, unless a waiver of compliance under § 61.11 of this part is granted, or by the date of initial startup for a new source with an initial startup after the effective date, a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests have been carried out in accordance with this subpart. If a waiver of compliance is granted under § 61.11, the certification of equipment necessary to comply with these standards shall be submitted by the date the waiver of compliance expires.

(2) Beginning on the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that updates the information listed in paragraphs (a)(1) through (a)(3) of this section. If the information in the annual report required by paragraphs (a)(1) through (a)(3) of this section is not changed in the following year, the owner or operator may submit a statement to that effect.

(3) If an owner or operator elects to comply with the requirements of § 61.342(c)(3)(ii), then the report required by paragraph (d)(2) of this section shall include a table identifying each waste stream chosen for exemption and the total annual benzene quantity in these exempted streams.

(4) If an owner or operator elects to comply with the alternative requirements of § 61.342(d) of this subpart, then he shall include in the report required by paragraph (d)(2) of this section a table presenting the following information for each process wastewater stream:

(i) Whether or not the process wastewater stream is being controlled for benzene emissions in accordance with the requirements of this subpart;

(ii) For each process wastewater stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(iii) For each process wastewater stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart, the table shall report the following information for the process wastewater stream as determined at the exit to the treatment process: Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(5) If an owner or operator elects to comply with the alternative requirements of § 61.342(e), then the report required by paragraph (d)(2) of this section shall include a table presenting the following information for each waste stream:

(i) For each waste stream identified as not being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as determined at the point of waste generation: annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity;

(ii) For each waste stream identified as being controlled for benzene emissions in accordance with the requirements of this subpart; the table shall report the following information for the waste stream as

determined at the applicable location described in § 61.355(k)(2): Annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

(6) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit quarterly to the Administrator a certification that all of the required inspections have been carried out in accordance with the requirements of this subpart.

(7) Beginning 3 months after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit a report quarterly to the Administrator that includes:

(i) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(1) of this subpart, then each period of operation during which the concentration of benzene in the monitored waste stream exiting the unit is equal to or greater than 10 ppmw.

(ii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(a)(2) of this subpart, then each 3-hour period of operation during which the average value of the monitored parameter is outside the range of acceptable values or during which the unit is not operating as designed.

(iii) If a treatment process or wastewater treatment system unit is monitored in accordance with § 61.354(b), then each period of operation during which the flow-weighted annual average concentration of benzene in the monitored waste stream entering the unit is equal to or greater than 10 ppmw and/or the total annual benzene quantity is equal to or greater than 1.0 mg/yr.

(iv) For a control device monitored in accordance with § 61.354(c) of this subpart, each period of operation monitored during which any of the following conditions occur, as applicable to the control device:

(A) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a thermal vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(B) Each 3-hour period of operation during which the average temperature of the gas stream immediately before the catalyst bed of a catalytic vapor incinerator, as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design gas stream temperature, and any 3-hour period during which the average temperature difference across the catalyst bed (i.e., the difference between the temperatures of the gas stream immediately before and after the catalyst bed), as measured by the temperature monitoring device, is less than 80 percent of the design temperature difference.

(C) Each 3-hour period of operation during which the average temperature of the gas stream in the combustion zone of a boiler or process heater having a design heat input capacity less than 44 MW (150 × 10<sup>6</sup> BTU/hr), as measured by the temperature monitoring device, is more than 28 °C (50 °F) below the design combustion zone temperature.

(D) Each 3-hour period of operation during which the average concentration of organics or the average concentration of benzene in the exhaust gases from a carbon adsorber, condenser, or other vapor recovery system is more than 20 percent greater than the design concentration level of organics or benzene in the exhaust gas.

(E) Each 3-hour period of operation during which the temperature of the condenser exhaust vent stream is more than 6 °C (11 °F) above the design average exhaust vent stream temperature, or the temperature of the coolant fluid exiting the condenser is more than 6 °C (11 °F) above the design average coolant fluid temperature at the condenser outlet.

(F) Each period in which the pilot flame of a flare is absent.

(G) Each occurrence when there is a change in the location at which the vent stream is introduced into the flame zone of a boiler or process heater as required by § 61.349(a)(2)(i)(C) of this subpart.

(H) Each occurrence when the carbon in a carbon adsorber system that is regenerated directly on site in the control device is not regenerated at the predetermined carbon bed regeneration time.

(I) Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly on site in the control device is not replaced at the predetermined interval specified in § 61.354(c) of this subpart.

(J) Each 3-hour period of operation during which the parameters monitored are outside the range of values specified in § 61.349(a)(2)(iv)(C), or any other periods specified by the Administrator for a control device subject to the requirements of § 61.349(a)(2)(iv).

(v) For a cover and closed-vent system monitored in accordance with § 61.354(g), the owner or operator shall submit a report quarterly to the Administrator that identifies any period in which the pressure in the waste management unit is equal to or greater than atmospheric pressure.

(8) Beginning one year after the date that the equipment necessary to comply with these standards has been certified in accordance with paragraph (d)(1) of this section, the owner or operator shall submit annually to the Administrator a report that summarizes all inspections required by §§ 61.342 through 61.354 during which detectable emissions are measured or a problem (such as a broken seal, gap or other problem) that could result in benzene emissions is identified, including information about the repairs or corrective action taken.

(e) An owner or operator electing to comply with the provisions of §§ 61.351 or 61.352 of this subpart shall notify the Administrator of the alternative standard selected in the report required under § 61.07 or § 61.10 of this part.

(f) An owner or operator who elects to install and operate the control equipment in § 61.351 of this subpart shall comply with the reporting requirements in 40 CFR 60.115b.

(g) An owner or operator who elects to install and operate the control equipment in § 61.352 of this subpart shall submit initial and quarterly reports that identify all seal gap measurements, as required in 40 CFR 60.693-2(a), that are outside the prescribed limits.

[55 FR 8346, Mar. 7 1990; 55 FR 12444, Apr. 3, 1990, as amended at 55 FR 37231, Sept. 10, 1990; 58 FR 3105, Jan. 7, 1993; 65 FR 62161, Oct. 17, 2000]

#### **§ 61.358 Delegation of authority.**

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Clean Air Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Alternative means of emission limitation under § 61.353 of this subpart will not be delegated to States.

## § 61.359 [Reserved]

### Appendix A to Part 61

#### APPENDIX A

#### National Emission Standards for Hazardous Air Pollutants Compliance Status Information

##### I. SOURCE REPORT

INSTRUCTIONS: Owners or operators of sources of hazardous pollutants subject to the National Emission Standards for Hazardous Air Pollutants are required to submit the information contained in Section I to the appropriate U.S. Environmental Protection Agency Regional Office prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

A list of regional offices is provided in §61.04.

##### A. SOURCE INFORMATION

##### 1. Identification/Location - Indicate the name and address of each source.

1	2	3	4	5	8	9	13	0	0	0	0	0	1							
Region	State		County		Source Number			14	16	17	18	19								
20	22	23	26	27 Source Name									46							
AQCR #		City Code		47 Street Address (Location of Plant)									66	80						
Dup 1-10													19	20	City Name		34	State	35	39
40 State Regs. Number													54	55	NEOS X Ref.		58			
59 SIC													62	FF	8	77	79	80		
64													65	Staff						
Dup 1-10													5	CS	STP	EC	80			
19													30	31	49					

##### 2. Contact - Indicate the name and telephone number of the owner or operator or other responsible official whom EPA may contact concerning this report.

Dup 1-18 4 1 19 20 21 Name 43

44 46  
Area Code 47 Number 54 80

3. Source Description - Briefly state the nature of the source (e.g., "Chlor-alkali Plant" or "Machine Shop").

Dup 1-18 4 2 19 20 21 Description 50

51 Continued 79 80

4. Alternative Mailing Address - Indicate an alternative mailing address if correspondence is to be directed to a location different than that specified above.

Dup 1-18 4 3 19 20 21 Number Street or Box Number 45 80

Dup 1-18 4 4 19 20 21 City 35 37 38 State 41 Zip 44 80

5. Compliance Status - The emissions from this source can not meet the emission limitations contained in the National Emission Standards on or prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

Signature of Owner, Operator or Other Responsible Official

NOTE: If the emissions from the source will exceed those limits set by the National Emission Standards for Hazardous Air Pollutants, the source will be in violation and subject to Federal enforcement actions unless granted a waiver of compliance by the Administrator of the U.S. Environmental Protection Agency. The information needed for such waivers is listed in Section II of this form.

B. PROCESS INFORMATION. Part B should be completed separately for each point of emission for each hazardous pollutant. [Sources subject to 61.22(l) may omit number 4. below.]

Dup 1-13 14 16 17 18 19 20 SCC 27 28 29 30 31  
NEQS X Ref LS SIP

1. Pollutant Emitted - Indicate the type of hazardous pollutant emitted by the process. Indicate "AS" for asbestos, "BE" for beryllium, or "HG" for mercury.

32 33  
Pollutant 34 Regulation 48 49  
EC

2. Process Description - Provide a brief description of each process (e.g., "hydrogen and box" in a mercury chlor-alkali plant, "grinding machine" in a beryllium machine shop). Use additional sheets if necessary.

50 Process Description 74 80

Dup 1-18 6 1 19 20 21 50

51 79 80

Dup 1-18 6 2 19 20 21 50

51 79 80

3. Amount of Pollutant - Indicate the average weight of the hazardous material named in Item 1 which enters the process in pounds per month (based on the previous twelve months of operation).

Dup 1-18 6 3 19 20 21 lbs./mo. 29 36 80

4. Control Devices

a. Indicate the type of pollution control devices, if any, used to reduce the emissions from the process (e.g., venturi scrubber, baghouse, wet cyclone) and the estimated percent of the pollutant which the device removes from the process gas stream.

Dup 1-18 6 4 19 20 21 PRIMARY CONTROL DEVICE: 43

45 Primary Device Name 64 66 70 Percent Removal Efficiency 72 79

80

Dup 1-18		6 5		SECONDARY CONTROL DEVICES:		45	
19	20	21					
47 Secondary Device Name		64	68	70		% EFFIC.	
		Percent Removal Efficiency				72	79 80

b. Asbestos Emission Control Devices Only

1. If a baghouse is specified in Item 4a, give the following information:

The air flow permeability in cubic feet per minute per square foot of fabric area.

Air flow permeability = \_\_\_\_\_ cfm/ft<sup>2</sup>

The pressure drop in inches water gauge across the filter at which the baghouse is operated.

Operating pressure drop = \_\_\_\_\_ inches w.g.

If the baghouse material contains synthetic fill yarn, check whether this material is / / spun / / or not spun.

If the baghouse utilizes a felted fabric, give the minimum thickness in inches and the density in ounces per square yard.

Thickness = \_\_\_\_\_ inches Density = \_\_\_\_\_ oz/yd<sup>2</sup>

11. If a wet collection device is specified in Item 4a, give the designed unit contacting energy in inches water gauge.

Unit contacting energy = \_\_\_\_\_ inches w.g.

C. DISPOSAL OF ASBESTOS-CONTAINING WASTES. Part C should be completed separately for each asbestos-containing waste generation operation arising from sources subject to §61.22(a), (c), (e), and (h).

Dup 1-13		0 0		5									
14	16	17	18	19	20	SCC	27	28	29	30	31		
A B								NEOS X Ref		CS		SIP	
32	33	34	Regulation		48	49							
Pollutant						EC							

1. Waste Generation - Provide a brief description of each process that generates asbestos-containing waste (e.g. disposal of control device wastes).

50 \_\_\_\_\_ Process Description \_\_\_\_\_ 79 80

2. Asbestos Concentration - Indicate the average percentage asbestos content of these materials.

Dup 1-18 6 1 ASBESTOS CONCENTRATION: 43 45 48

%  
50 80

3. Amount of Wastes - Indicate the average weight of asbestos-containing wastes disposed of, measured in kg/day.

Dup 1-18 6 2 kg/day 27 29 34 80

4. Control Methods - Indicate the emission control methods used in all stages of waste disposal, from collection, processing, and packaging to transporting and deposition.

Dup 1-18 6 3 Primary Control Method 43

45 \_\_\_\_\_ 79 80

Dup 1-18 6 4 21 \_\_\_\_\_ 50

51 \_\_\_\_\_ 79 80

5. Waste Disposal - Indicate the type of disposal site (sanitary landfill, open, covered) or incineration site (municipal, private) where the waste is disposed of and who operates the site (company, private, municipal). State the name and location of the site (closest city or town, county, state).

Dup 1-18 6 5 TYPE OF SITE: 33 35 50

51 \_\_\_\_\_ 79 80



Dup 1-18 6 6 19 20 21 OPERATOR: 29 31 50  
51 79 80  
Dup 1-18 6 7 19 20 21 LOCATION: 29  
31 70  
71 79 80

D. WASTE DISPOSAL SITES. Part D should be completed separately for each asbestos waste disposal site subject to section 61.22(l).

Dup 1-13 14 16 17 18 19 20 SCC 27 28 29 30 31  
NEDS X Ref CS SIP  
A B  
32 33  
Pollutant 34 Regulation 48 49  
EC  
WASTE DISPOSAL SITE 50 58 80  
1. Description - Provide a brief description of the site, including its size and configuration, and the distance to the closest city or town, closest residence, and closest primary road.  
Dup 1-18 6 1 19 20 21 SITE DESCRIPTION 37 39 50  
51 79 80  
Dup 1-18 6 2 19 20 21 DISTANCE: 29 30 TOWN: 34 36 40 42 43 K M  
RESIDENCE: 45 54 56 60 62 63 K M ROAD: 65 69 71 75  
K M 77 78 80

2. Inactivation - After the site is inactivated, indicate the method or methods used to comply with the standard and send a list of the actions that will be undertaken to maintain the inactivated site.

Dup 1-18 6 8 19 20 21 COMPLIANCE METHOD/INACTIVE SITE: 52  
54 79 80

## II. WAIVER REQUESTS

A. *Waiver of Compliance.* Owners or operators of sources unable to operate in compliance with the National Emission Standards for Hazardous Air Pollutants prior to 90 days after the effective date of any standards or amendments which require the submission of such information may request a waiver of compliance from the Administrator of the U.S. Environmental Protection Agency for the time period necessary to install appropriate control devices or make modifications to achieve compliance. The Administrator may grant a waiver of compliance with the standard for a period not exceeding two years from the effective date of the hazardous pollutant standards, if he finds that such period is necessary for the installation of controls and that steps will be taken during the period of the waiver to assure that the health of persons will be protected from imminent endangerment.

The report information provided in Section I must accompany this application. Applications should be sent to the appropriate EPA regional office.

1. *Processes Involved* —Indicate the process or processes emitting hazardous pollutants to which emission controls are to be applied.

## 2. Controls

a. Describe the proposed type of control device to be added or modification to be made to the process to reduce the emission of hazardous pollutants to an acceptable level. (Use additional sheets if necessary.)

b. Describe the measures that will be taken during the waiver period to assure that the health of persons will be protected from imminent endangerment. (Use additional sheets if necessary.)

3. *Increments of Progress*—Specify the dates by which the following increments of progress will be met.

Date by which contracts for emission control systems or process modifications will be awarded; or date by which orders will be issued for the purchase of the component parts to accomplish emission control or process modification.

Dup 1-16      0 1 7  
17 19 53 54 55 60 61 MO/DY/YR 66 80

Date of initiation of on-site construction or installation of emission control equipment or process change.

Dup 1-16      0 2 7  
17 19 53 54 55 60 61 MO/DY/YR 66 80

Date by which on-site construction or installation of emission control equipment or process modification is to be completed.

Dup 1-16      0 3 7  
17 19 53 54 55 60 61 MO/DY/YR 66 80

Date by which final compliance is to be achieved.

Dup 1-16      0 4 7  
17 19 53 54 55 60 61 MO/DY/YR 66 80

B. *Waiver of Emission Tests.* A waiver of emission testing may be granted to owners or operators of sources subject to emission testing if, in the judgment of the Administrator of the Environmental Protection Agency the emissions from the source comply with the appropriate standard or if the owners or operators of the source have requested a waiver of compliance or have been granted a waiver of compliance.

This application should accompany the report information provided in Section I.

1. *Reason*—State the reasons for requesting a waiver of emission testing. If the reason stated is that the emissions from the source are within the prescribed limits, documentation of this condition must be attached.

Date  
Signature of the owner or operator

(Sec. 114, of the Clean Air Act as amended (42 U.S.C. 7414))

[40 FR 48303, Oct. 14, 1975, as amended at 43 FR 8800, Mar. 3, 1978; 50 FR 46295, Sept. 9, 1985]

## Appendix B to Part 61—Test Methods

Method 101—Determination of particulate and gaseous mercury emissions from chlor-alkali plants (air streams)

Method 101A—Determination of particulate and gaseous mercury emissions from sewage sludge incinerators

Method 102—Determination of particulate and gaseous mercury emissions from chlor-alkali plants (hydrogen streams)

Method 103—Beryllium screening method

Method 104—Determination of beryllium emissions from stationary sources

Method 105—Determination of mercury in wastewater treatment plant sewage sludges

Method 106—Determination of vinyl chloride emissions from stationary sources

Method 107—Determination of vinyl chloride content of in-process wastewater samples, and vinyl chloride content of polyvinyl chloride resin slurry, wet cake, and latex samples

Method 107A—Determination of vinyl chloride content of solvents, resin-solvent solution, polyvinyl chloride resin, resin slurry, wet resin, and latex samples

Method 108—Determination of particulate and gaseous arsenic emissions

Method 108A—Determination of arsenic content in ore samples from nonferrous smelters

Method 108B—Determination of arsenic content in ore samples from nonferrous smelters

Method 108C—Determination of arsenic content in ore samples from nonferrous smelters (molybdenum blue photometric procedure)

Method 111—Determination of Polonium—210 emissions from stationary sources

METHOD 101—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM CHLOR-ALKALI PLANTS (AIR STREAMS)

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5.

### 1.0 Scope and Application

#### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Hg emissions, including both particulate and gaseous Hg, from chlor-alkali plants and other sources (as specified in the regulations) where the carrier-gas stream in the duct or stack is principally air.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in acidic iodine monochloride (ICl) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

## 3.0 Definitions [Reserved]

## 4.0 Interferences

4.1 Sample Collection. Sulfur dioxide (SO<sub>2</sub>) reduces ICl and causes premature depletion of the ICl solution.

### 4.2 Sample Analysis.

4.2.1 ICl concentrations greater than 10<sup>-4</sup> molar inhibit the reduction of the Hg (II) ion in the aeration cell.

4.2.2 Condensation of water vapor on the optical cell windows causes a positive interference.

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method does not purport to address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid (HCl). Highly toxic and corrosive. Causes severe damage to tissues. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid (HNO<sub>3</sub>). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.3 Sulfuric Acid (H<sub>2</sub>SO<sub>4</sub>). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. 3 mg/m<sup>3</sup> will cause lung damage. 1 mg/m<sup>3</sup> for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

## 6.0 *Equipment and Supplies.*

6.1 Sample Collection. A schematic of the sampling train used in performing this method is shown in Figure 101-1; it is similar to the Method 5 sampling train. The following items are required for sample collection:

6.1.1 Probe Nozzle, Pitot Tube, Differential Pressure Gauge, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 6.1.1.1, 6.1.1.3, 6.1.1.4, 6.1.1.9, 6.1.2, and 6.1.3, respectively.

6.1.2 Probe Liner. Borosilicate or quartz glass tubing. A heating system capable of maintaining a gas temperature of  $120 \pm 14$  °C ( $248 \pm 25$  °F) at the probe exit during sampling may be used to prevent water condensation.

NOTE: Do not use metal probe liners.

6.1.3 Impingers. Four Greenburg-Smith impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, impingers that are modified by replacing the tip with a 13-mm ID (0.5-in.) glass tube extending to 13 mm (0.5 in.) from the bottom of the flask may be used.

6.1.4 Acid Trap. Mine Safety Appliances air line filter, Catalog number 81857, with acid absorbing cartridge and suitable connections, or equivalent.

6.2 Sample Recovery. The following items are needed for sample recovery:

6.2.1 Glass Sample Bottles. Leakless, with Teflon-lined caps, 1000- and 100-ml.

6.2.2 Graduated Cylinder. 250-ml.

6.2.3 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

6.2.4 Funnel. Glass, to aid in sample recovery.

6.3 Sample Preparation and Analysis. The following items are needed for sample preparation and analysis:

6.3.1 Atomic Absorption Spectrophotometer. Perkin-Elmer 303, or equivalent, containing a hollow-cathode mercury lamp and the optical cell described in Section 6.3.2.

6.3.2 Optical Cell. Cylindrical shape with quartz end windows and having the dimensions shown in Figure 101-2. Wind the cell with approximately 2 meters (6 ft) of 24-gauge Nichrome wire, or equivalent, and wrap with fiberglass insulation tape, or equivalent; do not let the wires touch each other.

6.3.3 Aeration Cell. Constructed according to the specifications in Figure 101-3. Do not use a glass frit as a substitute for the blown glass bubbler tip shown in Figure 101-3.

6.3.4 Recorder. Matched to output of the spectrophotometer described in Section 6.3.1.

6.3.5 Variable Transformer. To vary the voltage on the optical cell from 0 to 40 volts.

6.3.6 Hood. For venting optical cell exhaust.

6.3.7 Flow Metering Valve.

6.3.8 Rate Meter. Rotameter, or equivalent, capable of measuring to within 2 percent a gas flow of 1.5 liters/min (0.053 cfm).

6.3.9 Aeration Gas Cylinder. Nitrogen or dry, Hg-free air, equipped with a single-stage regulator.

6.3.10 Tubing. For making connections. Use glass tubing (ungreased ball and socket connections are recommended) for all tubing connections between the solution cell and the optical cell; do not use Tygon tubing, other types of flexible tubing, or metal tubing as substitutes. Teflon, steel, or copper tubing may be used between the nitrogen tank and flow metering valve (Section 6.3.7), and Tygon, gum, or rubber tubing between the flow metering valve and the aeration cell.

6.3.11 Flow Rate Calibration Equipment. Bubble flow meter or wet-test meter for measuring a gas flow rate of  $1.5 \pm 0.1$  liters/min ( $0.053 \pm 0.0035$  cfm).

6.3.12 Volumetric Flasks. Class A with penny head standard taper stoppers; 100-, 250-, 500-, and 1000-ml.

6.3.13 Volumetric Pipets. Class A; 1-, 2-, 3-, 4-, and 5-ml.

6.3.14 Graduated Cylinder. 50-ml.

6.3.15 Magnetic Stirrer. General-purpose laboratory type.

6.3.16 Magnetic Stirring Bar. Teflon-coated.

6.3.17 Balance. Capable of weighing to  $\pm 0.5$  g.

6.3.18 Alternative Analytical Apparatus. Alternative systems are allowable as long as they meet the following criteria:

6.3.18.1 A linear calibration curve is generated and two consecutive samples of the same aliquot size and concentration agree within 3 percent of their average.

6.3.18.2 A minimum of 95 percent of the spike is recovered when an aliquot of a source sample is spiked with a known concentration of Hg (II) compound.

6.3.18.3 The reducing agent should be added after the aeration cell is closed.

6.3.18.4 The aeration bottle bubbler should not contain a frit.

6.3.18.5 Any Tygon tubing used should be as short as possible and conditioned prior to use until blanks and standards yield linear and reproducible results.

6.3.18.6 If manual stirring is done before aeration, it should be done with the aeration cell closed.

6.3.18.7 A drying tube should not be used unless it is conditioned as the Tygon tubing above.

## 7.0 Reagents and Standards

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society; where such specifications are not available, use the best available grade.

### 7.1 Sample Collection. The following reagents are required for sample collection:

7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 1. If high concentrations of organic matter are not expected to be present, the analyst may eliminate the  $\text{KMnO}_4$  test for oxidizable organic matter. Use this water in all dilutions and solution preparations.

7.1.2 Nitric Acid, 50 Percent (v/v). Mix equal volumes of concentrated  $\text{HNO}_3$  and water, being careful to add the acid to the water slowly.

7.1.3 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at  $175^\circ\text{C}$  ( $350^\circ\text{F}$ ) for 2 hours. The tester may use new silica gel as received.

7.1.4 Potassium Iodide (KI) Solution, 25 Percent. Dissolve 250 g of KI in water, and dilute to 1 liter.

7.1.5 Iodine Monochloride Stock Solution, 1.0 M. To 800 ml of 25 percent KI solution, add 800 ml of concentrated HCl. Cool to room temperature. With vigorous stirring, slowly add 135 g of potassium iodate ( $\text{KIO}_3$ ), and stir until all free iodine has dissolved. A clear orange-red solution occurs when all the  $\text{KIO}_3$  has been added. Cool to room temperature, and dilute to 1800 ml with water. Keep the solution in amber glass bottles to prevent degradation.

7.1.6 Absorbing Solution, 0.1 M ICl. Dilute 100 ml of the 1.0 M ICl stock solution to 1 liter with water. Keep the solution in amber glass bottles and in darkness to prevent degradation. This reagent is stable for at least two months.

### 7.2 Sample Preparation and Analysis. The following reagents and standards are required for sample preparation and analysis:

#### 7.2.1 Reagents.

7.2.1.1 Tin (II) Solution. Prepare fresh daily, and keep sealed when not being used. Completely dissolve 20 g of tin (II) chloride (or 25 g of tin (II) sulfate) crystals (Baker Analyzed reagent grade or any other brand that will give a clear solution) in 25 ml of concentrated HCl. Dilute to 250 ml with water. Do not substitute  $\text{HNO}_3$ ,  $\text{H}_2\text{SO}_4$ , or other strong acids for the HCl.

7.2.1.2 Sulfuric Acid, 5 Percent (v/v). Dilute 25 ml of concentrated  $\text{H}_2\text{SO}_4$  to 500 ml with water.

#### 7.2.2 Standards

7.2.2.1 Hg Stock Solution, 1 mg Hg/ml. Prepare and store all Hg standard solutions in borosilicate glass containers. Completely dissolve 0.1354 g of Hg (II) chloride in 75 ml of water in a 100-ml glass volumetric flask. Add 10 ml of concentrated  $\text{HNO}_3$ , and adjust the volume to exactly 100 ml with water. Mix thoroughly. This solution is stable for at least one month.

7.2.2.2 Intermediate Hg Standard Solution, 10 µg Hg/ml. Prepare fresh weekly. Pipet 5.0 ml of the Hg stock solution (Section 7.2.2.1) into a 500-ml glass volumetric flask, and add 20 ml of the 5 percent H<sub>2</sub> SO<sub>4</sub> solution. Dilute to exactly 500 ml with water. Thoroughly mix the solution.

7.2.2.3 Working Hg Standard Solution, 200 ng Hg/ml. Prepare fresh daily. Pipet 5.0 ml of the intermediate Hg standard solution (Section 7.2.2.2) into a 250-ml volumetric glass flask. Add 10 ml of the 5 percent H<sub>2</sub> SO<sub>4</sub> and 2 ml of the 0.1 M ICl absorbing solution taken as a blank (Section 8.7.4.3), and dilute to 250 ml with water. Mix thoroughly.

## 8.0 Sample Collection, Preservation, Transport, and Storage

Because of the complexity of this method, testers should be trained and experienced with the test procedures to ensure reliable results. Since the amount of Hg that is collected generally is small, the method must be carefully applied to prevent contamination or loss of sample.

8.1 Pretest Preparation. Follow the general procedure outlined in Method 5, Section 8.1, except omit Sections 8.1.2 and 8.1.3.

8.2 Preliminary Determinations. Follow the general procedure outlined in Method 5, Section 8.2, with the exception of the following:

8.2.1 Select a nozzle size based on the range of velocity heads to assure that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

8.2.2 Perform test runs such that samples are obtained over a period or periods that accurately determine the maximum emissions that occur in a 24-hour period. In the case of cyclic operations, run sufficient tests for the accurate determination of the emissions that occur over the duration of the cycle. A minimum sample time of 2 hours is recommended. In some instances, high Hg or high SO<sub>2</sub> concentrations make it impossible to sample for the desired minimum time. This is indicated by reddening (liberation of free iodine) in the first impinger. In these cases, the sample run may be divided into two or more subruns to ensure that the absorbing solution is not depleted.

## 8.3 Preparation of Sampling Train.

8.3.1 Clean all glassware (probe, impingers, and connectors) by rinsing with 50 percent HNO<sub>3</sub>, tap water, 0.1 M ICl, tap water, and finally deionized distilled water. Place 100 ml of 0.1 M ICl in each of the first three impingers. Take care to prevent the absorbing solution from contacting any greased surfaces. Place approximately 200 g of preweighed silica gel in the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the silica gel container in a clean place for later use in the sample recovery. Alternatively, determine and record the weight of the silica gel plus impinger to the nearest 0.5 g.

8.3.2 Install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260 °C (500 °F). Use a fiberglass string gasket if temperatures are higher. See APTD-0576 (Reference 3 in Method 5) for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. Mark the probe with heat-resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

8.3.3 Assemble the train as shown in Figure 101-1, using (if necessary) a very light coat of silicone grease on all ground glass joints. Grease only the outer portion (see APTD-0576) to avoid the possibility of contamination by the silicone grease.



NOTE: An empty impinger may be inserted between the third impinger and the silica gel to remove excess moisture from the sample stream.

8.3.4 After the sampling train has been assembled, turn on and set the probe heating system, if applicable, at the desired operating temperature. Allow time for the temperatures to stabilize. Place crushed ice around the impingers.

8.4 Leak-Check Procedures. Follow the leak-check procedures outlined in Method 5, Section 8.4.

8.5 Sampling Train Operation. Follow the general procedure outlined in Method 5, Section 8.5. For each run, record the data required on a data sheet such as the one shown in Figure 101-4.

8.6 Calculation of Percent Isokinetic. Same as Method 5, Section 8.6.

8.7 Sample Recovery. Begin proper cleanup procedure as soon as the probe is removed from the stack at the end of the sampling period.

8.7.1 Allow the probe to cool. When it can be safely handled, wipe off any external particulate matter near the tip of the probe nozzle, and place a cap over it. Do not cap off the probe tip tightly while the sampling train is cooling. Capping would create a vacuum and draw liquid out from the impingers.

8.7.2 Before moving the sampling train to the cleanup site, remove the probe from the train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the impinger. Use either ground-glass stoppers, plastic caps, or serum caps to close these openings.

8.7.3 Transfer the probe and impinger assembly to a cleanup area that is clean, protected from the wind, and free of Hg contamination. The ambient air in laboratories located in the immediate vicinity of Hg-using facilities is not normally free of Hg contamination.

8.7.4 Inspect the train before and during disassembly, and note any abnormal conditions. Treat the samples as follows.

8.7.4.1 Container No. 1 (Impingers and Probe).

8.7.4.1.1 Using a graduated cylinder, measure the liquid in the first three impingers to within 1 ml. Record the volume of liquid present ( e.g., see Figure 5-6 of Method 5). This information is needed to calculate the moisture content of the effluent gas. (Use only glass storage bottles and graduated cylinders that have been precleaned as in Section 8.3.1) Place the contents of the first three impingers into a 1000-ml glass sample bottle.

8.7.4.1.2 Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover the Hg (and any condensate) from the probe nozzle, probe fitting, and probe liner as follows: Rinse these components with two 50-ml portions of 0.1 M ICI. Next, rinse the probe nozzle, fitting and liner, and each piece of connecting glassware between the probe liner and the back half of the third impinger with a maximum of 400 ml of water. Add all washings to the 1000-ml glass sample bottle containing the liquid from the first three impingers.

8.7.4.1.3 After all washings have been collected in the sample container, tighten the lid on the container to prevent leakage during shipment to the laboratory. Mark the height of the liquid to determine later whether leakage occurred during transport. Label the container to identify clearly its contents.

8.7.4.2 Container No. 2 (Silica Gel). Same as Method 5, Section 8.7.6.3.

8.7.4.3 Container No. 3 (Absorbing Solution Blank). Place 50 ml of the 0.1 M ICI absorbing solution in a 100-ml sample bottle. Seal the container. Use this blank to prepare the working Hg standard solution (Section 7.2.2.3).

## 9.0 Quality Control

### 9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
8.4 10.2	Sampling equipment leak-checks and calibration	Ensure accuracy and precision of sampling measurements.
10.5, 10.6	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.3.3	Check for matrix effects	Eliminate matrix effects.

### 9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

## 10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Before use, clean all glassware, both new and used, as follows: brush with soap and tap water, liberally rinse with tap water, soak for 1 hour in 50 percent  $\text{HNO}_3$ , and then rinse with deionized distilled water.

10.2 Sampling Equipment. Calibrate the sampling equipment according to the procedures outlined in the following sections of Method 5: Section 10.1 (Probe Nozzle), Section 10.2 (Pitot Tube Assembly), Section 10.3 (Metering System), Section 10.5 (Temperature Sensors), Section 10.6 (Barometer).

10.3 Aeration System Flow Rate Meter. Assemble the aeration system as shown in Figure 101-5. Set the outlet pressure on the aeration gas cylinder regulator to a minimum pressure of 500 mm Hg (10 psi), and use the flow metering valve and a bubble flowmeter or wet-test meter to obtain a flow rate of  $1.5 \pm 0.1$  liters/min ( $0.053 \pm 0.0035$  cfm) through the aeration cell. After the calibration of the aeration system flow rate meter is complete, remove the bubble flowmeter from the system.

10.4 Optical Cell Heating System. Using a 50-ml graduated cylinder, add 50 ml of water to the bottle section of the aeration cell, and attach the bottle section to the bubbler section of the cell. Attach the aeration cell to the optical cell and while aerating at  $1.5 \pm 0.1$  liters/min ( $0.053 \pm 0.0035$  cfm), determine the minimum variable transformer setting necessary to prevent condensation of moisture in the optical cell and in the connecting tubing. (This setting should not exceed 20 volts.)

### 10.5 Spectrophotometer and Recorder.

#### 10.5.1 The Hg response may be measured by either peak height or peak area.

NOTE: The temperature of the solution affects the rate at which elemental Hg is released from a solution and, consequently, it affects the shape of the absorption curve (area) and the point of maximum absorbance (peak height). Therefore, to obtain reproducible results, bring all solutions to room temperature before use.

10.5.2 Set the spectrophotometer wavelength at 253.7 nm, and make certain the optical cell is at the minimum temperature that will prevent water condensation. Then set the recorder scale as follows: Using a 50-ml graduated cylinder, add 50 ml of water to the aeration cell bottle. Add three drops of Antifoam B to the bottle, and then pipet 5.0 ml of the working Hg standard solution into the aeration cell.

NOTE: Always add the Hg-containing solution to the aeration cell after the 50 ml of water.

10.5.3 Place a Teflon-coated stirring bar in the bottle. Before attaching the bottle section to the bubbler section of the aeration cell, make certain that (1) the aeration cell exit arm stopcock (Figure 101-3) is closed (so that Hg will not prematurely enter the optical cell when the reducing agent is being added) and (2) there is no flow through the bubbler. If conditions (1) and (2) are met, attach the bottle section to the bubbler section of the aeration cell. Pipet 5 ml of tin (II) reducing solution into the aeration cell through the side arm, and immediately stopper the side arm. Stir the solution for 15 seconds, turn on the recorder, open the aeration cell exit arm stopcock, and immediately initiate aeration with continued stirring. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

#### 10.6 Calibration Curve.

10.6.1 After setting the recorder scale, repeat the procedure in Section 10.5 using 0.0-, 1.0-, 2.0-, 3.0-, 4.0-, and 5.0-ml aliquots of the working standard solution (final amount of Hg in the aeration cell is 0, 200, 400, 600, 800, and 1000 ng, respectively). Repeat this procedure on each aliquot size until two consecutive peaks agree within 3 percent of their average value.

NOTE: To prevent Hg carryover from one sample to another, do not close the aeration cell from the optical cell until the recorder pen has returned to the baseline.)

10.6.2 It should not be necessary to disconnect the aeration gas inlet line from the aeration cell when changing samples. After separating the bottle and bubbler sections of the aeration cell, place the bubbler section into a 600-ml beaker containing approximately 400 ml of water. Rinse the bottle section of the aeration cell with a stream of water to remove all traces of the tin (II) reducing agent. Also, to prevent the loss of Hg before aeration, remove all traces of the reducing agent between samples by washing with water. It will be necessary, however, to wash the aeration cell parts with concentrated HCl if any of the following conditions occur: (1) A white film appears on any inside surface of the aeration cell, (2) the calibration curve changes suddenly, or (3) the replicate samples do not yield reproducible results.

10.6.3 Subtract the average peak height (or peak area) of the blank (0.0-ml aliquot)—which must be less than 2 percent of recorder full scale—from the averaged peak heights of the 1.0-, 2.0-, 3.0-, 4.0-, and 5.0-ml aliquot standards. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Hg contamination of a reagent or carry-over of Hg from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total Hg weight in the aeration cell (in ng), and draw the best fit straight line. This line should either pass through the origin or pass through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. If the line does not pass through or very near to the origin, check for nonlinearity of the curve and for incorrectly prepared standards.

#### 11.0 Analytical Procedure

11.1 Sample Loss Check. Check the liquid level in each container to see whether liquid was lost during transport. If a noticeable amount of leakage occurred, either void the sample or use methods subject to the approval of the Administrator to account for the losses.

11.2 Sample Preparation. Treat each sample as follows:

11.2.1 Container No. 1 (Impingers and Probe). Carefully transfer the contents of Container No. 1 into a 1000-ml volumetric flask, and adjust the volume to exactly 1000 ml with water.

11.2.2 Dilutions. Pipet a 2-ml aliquot from the diluted sample from Section 11.2.1 into a 250-ml volumetric flask. Add 10 ml of 5 percent  $\text{H}_2\text{SO}_4$ , and adjust the volume to exactly 250 ml with water. This solution is stable for at least 72 hours.

NOTE: The dilution factor will be 250/2 for this solution.

11.3 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.3 through 10.6.

11.3.1 Mercury Samples. Repeat the procedure used to establish the calibration curve with an appropriately sized aliquot (1 to 5 ml) of the diluted sample (from Section 11.2.2) until two consecutive peak heights agree within 3 percent of their average value. The peak maximum of an aliquot (except the 5-ml aliquot) must be greater than 10 percent of the recorder full scale. If the peak maximum of a 1.0-ml aliquot is off scale on the recorder, further dilute the original source sample to bring the Hg concentration into the calibration range of the spectrophotometer.

11.3.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.3.3 Check for Matrix Effects (optional). Use the Method of Standard Additions as follows to check at least one sample from each source for matrix effects on the Hg results. The Method of Standard Additions procedures described on pages 9-4 and 9-5 of the section entitled "General Information" of the Perkin Elmer Corporation Atomic Absorption Spectrophotometry Manual, Number 303-0152 (Reference 16 in Section 16.0) are recommended. If the results of the Method of Standard Additions procedure used on the single source sample do not agree to within  $\pm 5$  percent of the value obtained by the routine atomic absorption analysis, then reanalyze all samples from the source using the Method of Standard Additions procedure.

11.4 Container No. 2 (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. (This step may be conducted in the field.)

## 12.0 Data Analysis and Calculations

Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

12.1 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, and Isokinetic Variation. Same as Method 5, Sections 12.2 through 12.5 and 12.11, respectively.

12.2 Stack Gas Velocity. Using the data from this test and Equation 2-9 of Method 2, calculate the average stack gas velocity  $v_s$ .

12.3 Total Mercury.

12.3.1 For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the solution blank (see Section 10.6.3). Use the calibration curve and these corrected averages to determine the final total weight of Hg in ng in the aeration cell for each source sample.

12.3.2 Correct for any dilutions made to bring the sample into the working range of the spectrophotometer. Then calculate the Hg in the original solution,  $m_{Hg}$ , as follows:

$$m_{Hg} = \left[ C_{Hg(AC)} (DF) (V_f) (10^{-3}) \right] / S \quad \text{Eq. 101-1}$$

Where:

$C_{Hg(AC)}$  = Total ng of Hg in aliquot analyzed (reagent blank subtracted).

DF = Dilution factor for the Hg-containing solution (before adding to the aeration cell; e.g., DF = 250/2 if the source samples were diluted as described in Section 11.2.2).

$V_f$  = Solution volume of original sample, 1000 ml for samples diluted as described in Section 11.2.1.

$10^{-3}$  = Conversion factor,  $\mu\text{g}/\text{ng}$ .

S = Aliquot volume added to aeration cell, ml.

12.4 Mercury Emission Rate. Calculate the daily Hg emission rate, R, using Equation 101-2. For continuous operations, the operating time is equal to 86,400 seconds per day. For cyclic operations, use only the time per day each stack is in operation. The total Hg emission rate from a source will be the summation of results from all stacks.

$$R = \frac{K_1 m_{Hg} V_s A_s (86,400 \times 10^{-6})}{\left[ V_{m(std)} + V_{w(std)} \right] (T_s / P_s)} \quad \text{Eq. 101-2}$$

Where:

$K_1$  = 0.3858 °K/mm Hg for metric units.

$K_1$  = 17.64 °R/in. Hg for English units.

$K_3$  =  $10^{-6}$  g/ $\mu\text{g}$  for metric units.

= 2.2046 "  $\times 10^{-9}$  lb/ $\mu\text{g}$  for English units.

$P_s$  = Absolute stack gas pressure, mm Hg (in. Hg).

t = Daily operating time, sec/day.

$T_s$  = Absolute average stack gas temperature, °K (°R).

$V_{m(std)}$  = Dry gas sample volume at standard conditions, scm (scf).

$V_{w(std)}$  = Volume of water vapor at standard conditions, scm (scf).

12.5 Determination of Compliance. Each performance test consists of three repetitions of the applicable test method. For the purpose of determining compliance with an applicable national emission standard, use the average of the results of all repetitions.

### 13.0 Method Performance

The following estimates are based on collaborative tests, wherein 13 laboratories performed duplicate analyses on two Hg-containing samples from a chlor-alkali plant and on one laboratory-prepared sample of known Hg concentration. The sample concentrations ranged from 2 to 65 µg Hg/ml.

13.1 Precision. The estimated intra-laboratory and inter-laboratory standard deviations are 1.6 and 1.8 µg Hg/ml, respectively.

13.2 Accuracy. The participating laboratories that analyzed a 64.3 µg Hg/ml (in 0.1 M ICl) standard obtained a mean of 63.7 µg Hg/ml.

13.3 Analytical Range. After initial dilution, the range of this method is 0.5 to 120 µg Hg/ml. The upper limit can be extended by further dilution of the sample.

### 14.0 Pollution Prevention. [Reserved]

### 15.0 Waste Management. [Reserved]

### 16.0 References

Same as Method 5, Section 17.0, References 1-3, 5, and 6, with the addition of the following:

1. Determining Dust Concentration in a Gas Stream. ASME Performance Test Code No. 27. New York, NY. 1957.

2. DeVorkin, Howard, *et al.* Air Pollution Source Testing Manual. Air Pollution Control District. Los Angeles, CA. November 1963.

3. Hatch, W.R., and W.I. Ott. Determination of Sub-Microgram Quantities of Mercury by Atomic Absorption Spectrophotometry. *Anal. Chem.* 40:2085-87. 1968.

4. Mark, L.S. Mechanical Engineers' Handbook. McGraw-Hill Book Co., Inc. New York, NY. 1951.

5. Western Precipitation Division of Joy Manufacturing Co. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Bulletin WP-50. Los Angeles, CA. 1968.

6. Perry, J.H. Chemical Engineers' Handbook. McGraw-Hill Book Co., Inc. New York, NY. 1960.

7. Shigehara, R.T., W.F. Todd, and W.S. Smith. Significance of Errors in Stack Sampling Measurements. *Stack Sampling News.* 1 (3):6-18. September 1973.

8. Smith, W.S., R.T. Shigehara, and W.F. Todd. A Method of Interpreting Stack Sampling Data. *Stack Sampling News.* 1 (2):8-17. August 1973.

9. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Annual Book of ASTM Standards, Part 23. ASTM Designation D 2928-71. Philadelphia, PA 1971.

10. Vennard, J.K. Elementary Fluid Mechanics. John Wiley and Sons, Inc. New York. 1947.
11. Mitchell, W.J. and M.R. Midgett. Improved Procedure for Determining Mercury Emissions from Mercury Cell Chlor-Alkali Plants. J. APCA. 26 :674-677. July 1976.
12. Shigehara, R.T. Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News. 2 :4-11. October 1974.
13. Vollaro, R.F. Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, NC. November 1976.
14. Klein, R. and C. Hach. Standard Additions: Uses and Limitation in Spectrophotometric Measurements. Amer. Lab. 9 :21. 1977.
15. Perkin Elmer Corporation. Analytical Methods for Atomic Absorption Spectrophotometry. Norwalk, Connecticut. September 1976.

*17.0 Tables, Diagrams, Flowcharts, and Validation Data*

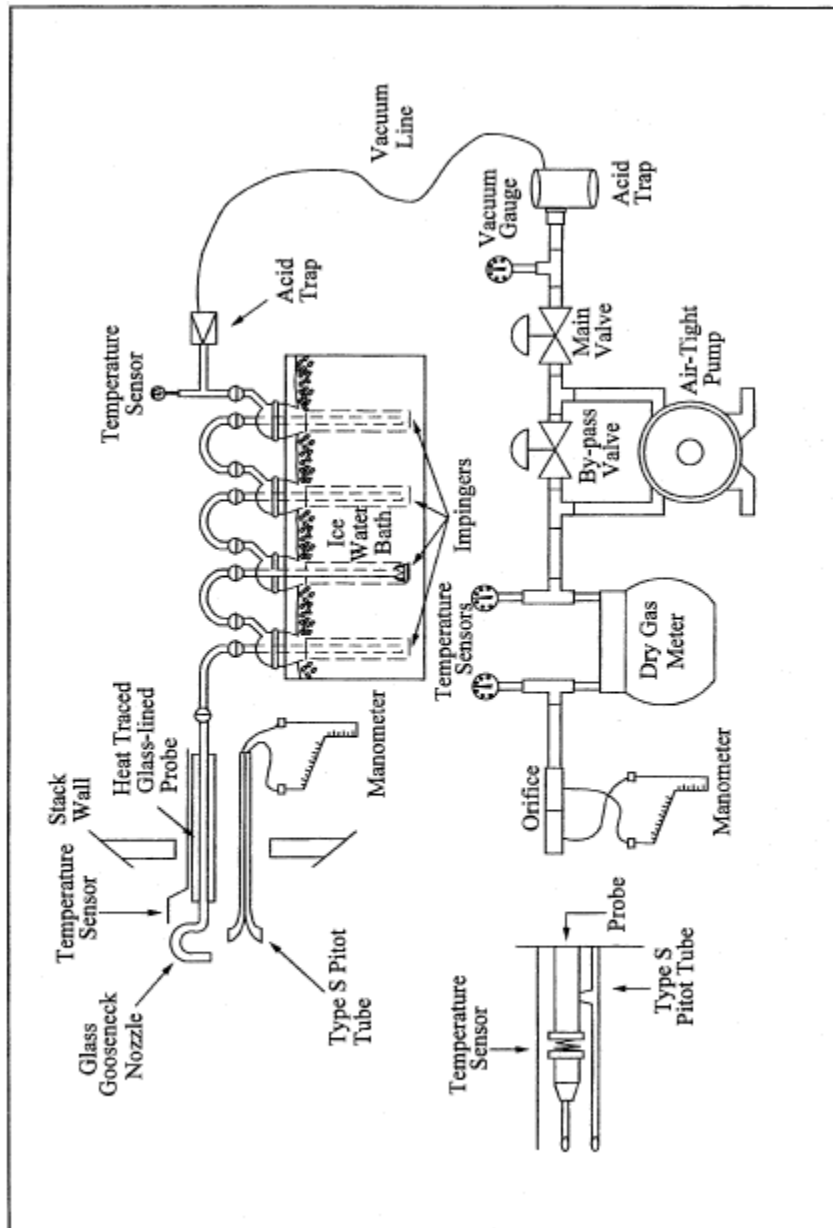


Figure 101-1. Mercury Sampling Train.



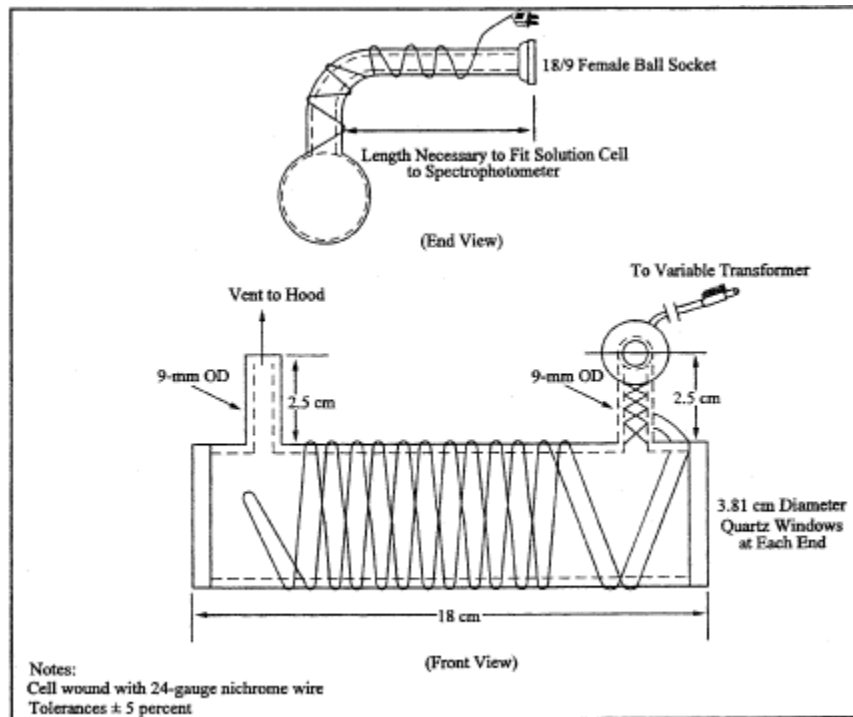


Figure 101-2. Optical Cell.

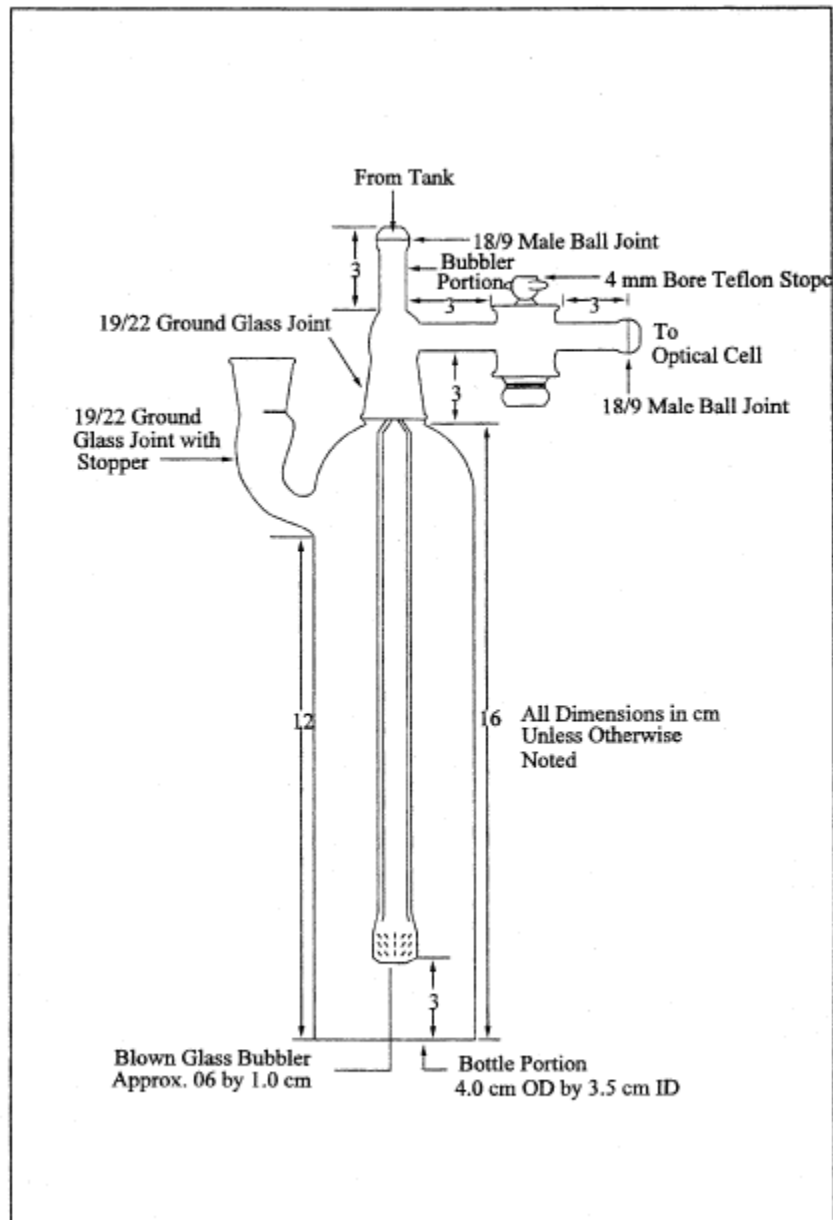


Figure 101-3. Aeration Cell.



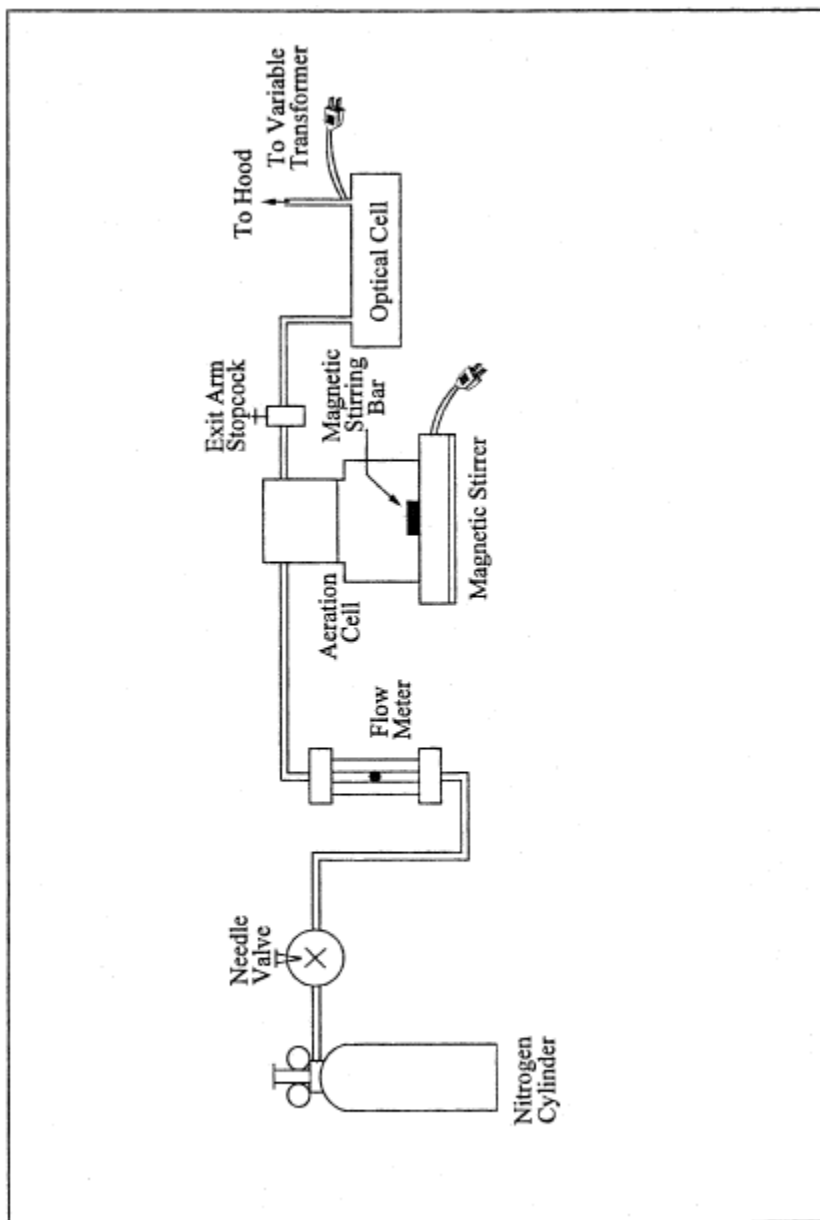


Figure 101-5. Schematic of Aeration System.

#### METHOD 101A—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM SEWAGE SLUDGE INCINERATORS

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60 and in this part. Therefore, to obtain reliable results, persons using this method should also have a thorough knowledge of at least the following additional test methods: Methods 1, Method 2, Method 3, and Method 5 of part 60 (appendix A), and Method 101 part 61 (appendix B).

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon spectrophotometer and recorder.

1.2 Applicability. This method is applicable for the determination of Hg emissions from sewage sludge incinerators and other sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

2.1 Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and are collected in acidic potassium permanganate ( $\text{KMnO}_4$ ) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

## 3.0 Definitions. [Reserved]

## 4.0 Interferences

4.1 Sample Collection. Excessive oxidizable organic matter in the stack gas prematurely depletes the  $\text{KMnO}_4$  solution and thereby prevents further collection of Hg.

4.2 Analysis. Condensation of water vapor on the optical cell windows causes a positive interference.

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid ( $\text{HNO}_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.3 Sulfuric acid ( $\text{H}_2\text{SO}_4$ ). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. May cause lung tissue damage with edema.  $3 \text{ mg/m}^3$  will cause lung damage in uninitiated.  $1 \text{ mg/m}^3$  for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

5.3 Chlorine Evolution. Hydrochloric acid reacts with  $\text{KMnO}_4$  to liberate chlorine gas. Although this is a minimal concern when small quantities of HCl (5-10 ml) are used in the impinger rinse, a potential safety hazard may still exist. At sources that emit higher concentrations of oxidizable materials ( e.g., power plants), more HCl may be required to remove the larger amounts of brown deposit formed in the impingers. In such cases, the potential safety hazards due to sample container pressurization are greater, because of the larger volume of HCl rinse added to the recovered sample. These hazards are eliminated by storing and analyzing the HCl impinger wash separately from the permanganate impinger sample.

## 6.0 Equipment and Supplies

6.1 Sample Collection and Sample Recovery. Same as Method 101, Sections 6.1 and 6.2, respectively, with the following exceptions:

6.1.1 Probe Liner. Same as in Method 101, Section 6.1.2, except that if a filter is used ahead of the impingers, the probe heating system must be used to minimize the condensation of gaseous Hg.

6.1.2 Filter Holder (Optional). Borosilicate glass with a rigid stainless-steel wire-screen filter support (do not use glass frit supports) and a silicone rubber or Teflon gasket, designed to provide a positive seal against leakage from outside or around the filter. The filter holder must be equipped with a filter heating system capable of maintaining a temperature around the filter holder of  $120 \pm 14^\circ\text{C}$  ( $248 \pm 25^\circ\text{F}$ ) during sampling to minimize both water and gaseous Hg condensation. A filter may also be used in cases where the stream contains large quantities of particulate matter.

6.2 Sample Analysis. Same as Method 101, Section 6.3, with the following additions and exceptions:

6.2.1 Volumetric Pipets. Class A; 1-, 2-, 3-, 4-, 5-, 10-, and 20-ml.

6.2.2 Graduated Cylinder. 25-ml.

6.2.3 Steam Bath.

6.2.4 Atomic Absorption Spectrophotometer or Equivalent. Any atomic absorption unit with an open sample presentation area in which to mount the optical cell is suitable. Instrument settings recommended by the particular manufacturer should be followed. Instruments designed specifically for the measurement of mercury using the cold-vapor technique are commercially available and may be substituted for the atomic absorption spectrophotometer.

6.2.5 Optical Cell. Alternatively, a heat lamp mounted above the cell or a moisture trap installed upstream of the cell may be used.

6.2.6 Aeration Cell. Alternatively, aeration cells available with commercial cold vapor instrumentation may be used.

6.2.7 Aeration Gas Cylinder. Nitrogen, argon, or dry, Hg-free air, equipped with a single-stage regulator. Alternatively, aeration may be provided by a peristaltic metering pump. If a commercial cold vapor instrument is used, follow the manufacturer's recommendations.

## 7.0 Reagents and Standards

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Collection and Recovery. The following reagents are required for sample collection and recovery:

7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 Type 1. If high concentrations of organic matter are not expected to be present, the analyst may eliminate the  $\text{KMnO}_4$  test for oxidizable organic matter. Use this water in all dilutions and solution preparations.

7.1.2 Nitric Acid, 50 Percent (V/V). Mix equal volumes of concentrated  $\text{HNO}_3$  and water, being careful to add the acid to the water slowly.

7.1.3 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at  $175^\circ\text{C}$  ( $350^\circ\text{F}$ ) for 2 hours. New silica gel may be used as received.

7.1.4 Filter (Optional). Glass fiber filter, without organic binder, exhibiting at least 99.95 percent efficiency on  $0.3\text{-}\mu\text{m}$  dioctyl phthalate smoke particles. The filter in cases where the gas stream contains large quantities of particulate matter, but blank filters should be analyzed for Hg content.

7.1.5 Sulfuric Acid, 10 Percent (V/V). Carefully add and mix 100 ml of concentrated  $\text{H}_2\text{SO}_4$  to 900 ml of water.

7.1.6 Absorbing Solution, 4 Percent  $\text{KMnO}_4$  (W/V). Prepare fresh daily. Dissolve 40 g of  $\text{KMnO}_4$  in sufficient 10 percent  $\text{H}_2\text{SO}_4$  to make 1 liter. Prepare and store in glass bottles to prevent degradation.

7.1.7 Hydrochloric Acid, 8 N. Carefully add and mix 67 ml of concentrated  $\text{HCl}$  to 33 ml of water.

7.2 Sample Analysis. The following reagents and standards are required for sample analysis:

7.2.1 Water. Same as in Section 7.1.1.

7.2.2 Tin (II) Solution. Prepare fresh daily, and keep sealed when not being used. Completely dissolve 20 g of tin (II) chloride (or 25 g of tin (II) sulfate) crystals (Baker Analyzed reagent grade or any other brand that will give a clear solution) in 25 ml of concentrated  $\text{HCl}$ . Dilute to 250 ml with water. Do not substitute  $\text{HNO}_3$ ,  $\text{H}_2\text{SO}_4$ , or other strong acids for the  $\text{HCl}$ .

7.2.3 Sodium Chloride-Hydroxylamine Solution. Dissolve 12 g of sodium chloride and 12 g of hydroxylamine sulfate (or 12 g of hydroxylamine hydrochloride) in water and dilute to 100 ml.

7.2.4 Hydrochloric Acid, 8 N. Same as Section 7.1.7.

7.2.5 Nitric Acid, 15 Percent (V/V). Carefully add 15 ml  $\text{HNO}_3$  to 85 ml of water.

7.2.6 Antifoam B Silicon Emulsion. J.T. Baker Company (or equivalent).

7.2.7 Mercury Stock Solution, 1 mg Hg/ml. Prepare and store all Hg standard solutions in borosilicate glass containers. Completely dissolve 0.1354 g of Hg (II) chloride in 75 ml of water. Add 10

ml of concentrated  $\text{HNO}_3$ , and adjust the volume to exactly 100 ml with water. Mix thoroughly. This solution is stable for at least one month.

7.2.8 Intermediate Hg Standard Solution, 10  $\mu\text{g}/\text{ml}$ . Prepare fresh weekly. Pipet 5.0 ml of the Hg stock solution (Section 7.2.7) into a 500 ml volumetric flask, and add 20 ml of 15 percent  $\text{HNO}_3$  solution. Adjust the volume to exactly 500 ml with water. Thoroughly mix the solution.

7.2.9 Working Hg Standard Solution, 200 ng Hg/ml. Prepare fresh daily. Pipet 5.0 ml from the "Intermediate Hg Standard Solution" (Section 7.2.8) into a 250-ml volumetric flask. Add 5 ml of 4 percent  $\text{KMnO}_4$  absorbing solution and 5 ml of 15 percent  $\text{HNO}_3$ . Adjust the volume to exactly 250 ml with water. Mix thoroughly.

7.2.10 Potassium Permanganate, 5 Percent (W/V). Dissolve 5 g of  $\text{KMnO}_4$  in water and dilute to 100 ml.

7.2.11 Filter. Whatman No. 40, or equivalent.

## 8.0 Sample Collection, Preservation, Transport, and Storage

Same as Method 101, Section 8.0, with the exception of the following:

8.1 Preliminary Determinations. Same as Method 101, Section 8.2, except that the liberation of free iodine in the first impinger due to high Hg or sulfur dioxide concentrations is not applicable. In this method, high oxidizable organic content may make it impossible to sample for the desired minimum time. This problem is indicated by the complete bleaching of the purple color of the  $\text{KMnO}_4$  solution. In cases where an excess of water condensation is encountered, collect two runs to make one sample, or add an extra impinger in front of the first impinger (also containing acidified  $\text{KMnO}_4$  solution).

8.2 Preparation of Sampling Train. Same as Method 101, Section 8.3, with the exception of the following:

8.2.1 In this method, clean all the glass components by rinsing with 50 percent  $\text{HNO}_3$ , tap water, 8 N HCl, tap water, and finally with deionized distilled water. Then place 50 ml of absorbing solution in the first impinger and 100 ml in each of the second and third impingers.

8.2.2 If a filter is used, use a pair of tweezers to place the filter in the filter holder. Be sure to center the filter, and place the gasket in the proper position to prevent the sample gas stream from bypassing the filter. Check the filter for tears after assembly is completed. Be sure also to set the filter heating system at the desired operating temperature after the sampling train has been assembled.

8.3 Sampling Train Operation. In addition to the procedure outlined in Method 101, Section 8.5, maintain a temperature around the filter (if applicable) of  $120 \pm 14^\circ\text{C}$  ( $248 \pm 25^\circ\text{F}$ ).

8.4 Sample Recovery. Same as Method 101, Section 8.7, with the exception of the following:

8.4.1 Transfer the probe, impinger assembly, and (if applicable) filter assembly to the cleanup area.

8.4.2 Treat the sample as follows:

8.4.2.1 Container No. 1 (Impinger, Probe, and Filter Holder) and, if applicable, Container No. 1A (HCl rinse).



8.4.2.1.1 Using a graduated cylinder, measure the liquid in the first three impingers to within 1 ml. Record the volume of liquid present ( e.g., see Figure 5-6 of Method 5). This information is needed to calculate the moisture content of the effluent gas. (Use only graduated cylinder and glass storage bottles that have been precleaned as in Section 8.2.1.) Place the contents of the first three impingers (four if an extra impinger was added as described in Section 8.1) into a 1000-ml glass sample bottle labeled Container No. 1.

NOTE: If a filter is used, remove the filter from its holder as outlined under Section 8.4.3.

8.4.2.1.2 Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover the Hg (and any condensate) from the probe nozzle, probe fitting, probe liner, front half of the filter holder (if applicable), and impingers as follows: Rinse these components with a total of 400 ml (350 ml if an extra impinger was added as described in Section 8.1) of fresh absorbing solution, carefully assuring removal of all loose particulate matter from the impingers; add all washings to the 1000 ml glass sample bottle. To remove any residual brown deposits on the glassware following the permanganate rinse, rinse with approximately 100 ml of water, carefully assuring removal of all loose particulate matter from the impingers. Add this rinse to Container No. 1.

8.4.2.1.3 If no visible deposits remain after this water rinse, do not rinse with 8 N HCl. If deposits do remain on the glassware after the water rinse, wash impinger walls and stems with 25 ml of 8 N HCl, and place the wash in a separate container labeled Container No. 1A as follows: Place 200 ml of water in a sample container labeled Container No. 1A. Wash the impinger walls and stem with the HCl by turning the impinger on its side and rotating it so that the HCl contacts all inside surfaces. Pour the HCl wash carefully with stirring into Container No. 1A.

8.4.2.1.4 After all washings have been collected in the appropriate sample container(s), tighten the lid(s) on the container(s) to prevent leakage during shipment to the laboratory. Mark the height of the fluid level to allow subsequent determination of whether leakage has occurred during transport. Label each container to identify its contents clearly.

8.4.3 Container No. 2 (Silica Gel). Same as Method 5, Section 8.7.6.3.

8.4.4 Container No. 3 (Filter). If a filter was used, carefully remove it from the filter holder, place it in a 100-ml glass sample bottle, and add 20 to 40 ml of absorbing solution. If it is necessary to fold the filter, be sure that the particulate cake is inside the fold. Carefully transfer to the 100-ml sample bottle any particulate matter and filter fibers that adhere to the filter holder gasket by using a dry Nylon bristle brush and a sharp-edged blade. Seal the container. Label the container to identify its contents clearly. Mark the height of the fluid level to allow subsequent determination of whether leakage has occurred during transport.

8.4.5 Container No. 4 (Filter Blank). If a filter was used, treat an unused filter from the same filter lot as that used for sampling according to the procedures outlined in Section 8.4.4.

8.4.6 Container No. 5 (Absorbing Solution Blank). Place 650 ml of 4 percent  $\text{KMnO}_4$  absorbing solution in a 1000-ml sample bottle. Seal the container.

8.4.7 Container No. 6 (HCl Rinse Blank). Place 200 ml of water in a 1000-ml sample bottle, and add 25 ml of 8 N HCl carefully with stirring. Seal the container. Only one blank sample per 3 runs is required.

## 9.0 Quality Control

### 9.1 Miscellaneous Quality Control Measures.

Section	Quality control measure	Effect
8.0, 10.0	Sampling equipment leak-checks and calibration	Ensure accuracy and precision of sampling measurements.
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.3.3	Check for matrix effects	Eliminate matrix effects.

### 9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

## 10.0 Calibration and Standardization

Same as Method 101, Section 10.0, with the following exceptions:

10.1 Optical Cell Heating System Calibration. Same as in Method 101, Section 10.4, except use a 25 ml graduated cylinder to add 25 ml of water to the bottle section of the aeration cell.

### 10.2 Spectrophotometer and Recorder Calibration.

10.2.1 The Hg response may be measured by either peak height or peak area.

NOTE: The temperature of the solution affects the rate at which elemental Hg is released from a solution and, consequently, it affects the shape of the absorption curve (area) and the point of maximum absorbance (peak height). To obtain reproducible results, all solutions must be brought to room temperature before use.

10.2.2 Set the spectrophotometer wave length at 253.7 nm, and make certain the optical cell is at the minimum temperature that will prevent water condensation. Then set the recorder scale as follows: Using a 25-ml graduated cylinder, add 25 ml of water to the aeration cell bottle. Add three drops of Antifoam B to the bottle, and then pipet 5.0 ml of the working Hg standard solution into the aeration cell.

NOTE: Always add the Hg-containing solution to the aeration cell after the 25 ml of water.

10.2.3 Place a Teflon-coated stirring bar in the bottle. Add 5 ml of absorbing solution to the aeration bottle, and mix well. Before attaching the bottle section to the bubbler section of the aeration cell, make certain that (1) the aeration cell exit arm stopcock (Figure 101-3 of Method 101) is closed (so that Hg will not prematurely enter the optical cell when the reducing agent is being added) and (2) there is no flow through the bubbler. If conditions (1) and (2) are met, attach the bottle section to the bubbler section of the aeration cell. Add sodium chloride-hydroxylamine in 1 ml increments until the solution is colorless. Now add 5 ml of tin (II) solution to the aeration bottle through the side arm, and immediately stopper the side arm. Stir the solution for 15 seconds, turn on the recorder, open the aeration cell exit arm stopcock, and immediately initiate aeration with continued stirring. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

## 11.0 Analytical Procedure

11.1 Sample Loss Check. Check the liquid level in each container to see if liquid was lost during transport. If a noticeable amount of leakage occurred, either void the sample or use methods subject to the approval of the Administrator to account for the losses.

11.2 Sample Preparation. Treat sample containers as follows:

11.2.1 Containers No. 3 and No. 4 (Filter and Filter Blank).

11.2.1.1 If a filter is used, place the contents, including the filter, of Containers No. 3 and No. 4 in separate 250-ml beakers, and heat the beakers on a steam bath until most of the liquid has evaporated. Do not heat to dryness. Add 20 ml of concentrated  $\text{HNO}_3$  to the beakers, cover them with a watch glass, and heat on a hot plate at 70 °C (160 °F) for 2 hours. Remove from the hot plate.

11.2.1.2 Filter the solution from digestion of the Container No. 3 contents through Whatman No. 40 filter paper, and save the filtrate for addition to the Container No. 1 filtrate as described in Section 11.2.2. Discard the filter paper.

11.2.1.3 Filter the solution from digestion of the Container No. 4 contents through Whatman No. 40 filter paper, and save the filtrate for addition to Container No. 5 filtrate as described in Section 11.2.3 below. Discard the filter paper.

11.2.2 Container No. 1 (Impingers, Probe, and Filter Holder) and, if applicable, No. 1A (HCl rinse).

11.2.2.1 Filter the contents of Container No. 1 through Whatman No. 40 filter paper into a 1 liter volumetric flask to remove the brown manganese dioxide ( $\text{MnO}_2$ ) precipitate. Save the filter for digestion of the brown  $\text{MnO}_2$  precipitate. Add the sample filtrate from Container No. 3 to the 1-liter volumetric flask, and dilute to volume with water. If the combined filtrates are greater than 1000 ml, determine the volume to the nearest ml and make the appropriate corrections for blank subtractions. Mix thoroughly. Mark the filtrate as analysis Sample No. A.1 and analyze for Hg within 48 hr of the filtration step. Place the saved filter, which was used to remove the brown  $\text{MnO}_2$  precipitate, into an appropriate sized container. In a laboratory hood, add 25 ml of 8 N HCl to the filter and allow to digest for a minimum of 24 hours at room temperature.

11.2.2.2 Filter the contents of Container 1A through Whatman No. 40 filter paper into a 500-ml volumetric flask. Then filter the digestate of the brown  $\text{MnO}_2$  precipitate from Container No. 1 through Whatman No. 40 filter paper into the same 500-ml volumetric flask, and dilute to volume with water. Mark this combined 500 ml dilute solution as analysis Sample No. A.2. Discard the filters.

11.2.3 Container No. 5 (Absorbing Solution Blank) and No. 6 (HCl Rinse Blank).

11.2.3.1 Treat Container No. 5 as Container No. 1 (as described in Section 11.2.2), except substitute the filter blank filtrate from Container No. 4 for the sample filtrate from Container No. 3, and mark as Sample A.1 Blank.

11.2.3.2 Treat Container No. 6 as Container No. 1A, (as described in Section 11.2.2, except substitute the filtrate from the digested blank  $\text{MnO}_2$  precipitate for the filtrate from the digested sample  $\text{MnO}_2$  precipitate, and mark as Sample No. A.2 Blank.

NOTE: When analyzing samples A.1 Blank and HCl A.2 Blank, always begin with 10 ml aliquots. This applies specifically to blank samples.

11.3 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Section 10.0.

11.3.1 Mercury Samples. Then repeat the procedure used to establish the calibration curve with appropriately sized aliquots (1 to 10 ml) of the samples (from Sections 11.2.2 and 11.2.3) until two consecutive peak heights agree within 3 percent of their average value. If the 10 ml sample is below the detectable limit, use a larger aliquot (up to 20 ml), but decrease the volume of water added to the aeration cell accordingly to prevent the solution volume from exceeding the capacity of the aeration bottle. If the peak maximum of a 1.0 ml aliquot is off scale, further dilute the original sample to bring the Hg concentration into the calibration range of the spectrophotometer. If the Hg content of the absorbing solution and filter blank is below the working range of the analytical method, use zero for the blank.

11.3.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration; recalibrate as necessary.

11.3.3 Check for Matrix Effects (optional). Same as Method 101, Section 11.3.3.

## 12.0 Data Analysis and Calculations

NOTE: Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

### 12.1 Nomenclature.

$C_{(filtr)Hg}$  = Total ng of Hg in aliquot of  $KMnO_4$  filtrate and  $HNO_3$  digestion of filter analyzed (aliquot of analysis Sample No. A.1).

$C_{(filtr\ blank)Hg}$  = Total ng of Hg in aliquot of  $KMnO_4$  blank and  $HNO_3$  digestion of blank filter analyzed (aliquot of analysis Sample No. A.1 blank).

$C_{(HCl\ blank)Hg}$  = Total ng of Hg analyzed in aliquot of the 500-ml analysis Sample No. HCl A.2 blank.

$C_{(HCl)Hg}$  = Total ng of Hg analyzed in the aliquot from the 500-ml analysis Sample No. HCl A.2.

DF = Dilution factor for the HCl-digested Hg-containing solution, Analysis Sample No. "HCl A.2."

$DF_{blank}$  = Dilution factor for the HCl-digested Hg containing solution, Analysis Sample No. "HCl A.2 blank."  
(Refer to sample No. "HCl A.2" dilution factor above.)

$m_{(filtr)Hg}$  = Total blank corrected  $\mu g$  of Hg in  $KMnO_4$  filtrate and  $HNO_3$  digestion of filter sample.

$m_{(HCl)Hg}$  = Total blank corrected  $\mu g$  of Hg in HCl rinse and HCl digestate of filter sample.

$m_{Hg}$  = Total blank corrected Hg content in each sample,  $\mu g$ .

S = Aliquot volume of sample added to aeration cell, ml.

$S_{blank}$  = Aliquot volume of blank added to aeration cell, ml.

$V_{f(blank)}$  = Solution volume of blank sample, 1000 ml for samples diluted as described in Section 11.2.2.

$V_{f(filtr)}$  = Solution volume of original sample, normally 1000 ml for samples diluted as described in Section 11.2.2.

$V_{f(HCl)}$  = Solution volume of original sample, 500 ml for samples diluted as described in Section 11.2.1.

$10^{-3}$  = Conversion factor,  $\mu\text{g}/\text{ng}$ .

12.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, Isokinetic Variation, and Stack Gas Velocity and Volumetric Flow Rate. Same as Method 5, Sections 12.2 through 12.5, 12.11, and 12.12, respectively.

### 12.3 Total Mercury.

12.3.1 For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the blank. Use the calibration curve and these corrected averages to determine the final total weight of Hg in ng in the aeration cell for each source sample.

12.3.2 Correct for any dilutions made to bring the sample into the working range of the spectrophotometer.

$$m_{(\text{HCl})\text{Hg}} = \frac{[C_{(\text{HCl})\text{Hg}} \text{DF}]}{S} - \frac{[C_{(\text{HCl} \text{bk})\text{Hg}} \text{DF}_{\text{bk}}]}{S_{\text{bk}}} V_{f(\text{HCl})} (10^{-3}) \quad \text{Eq. 101A-1}$$

NOTE: This dilution factor applies only to the intermediate dilution steps, since the original sample volume  $[(V_f)_{\text{HCL}}]$  of "HCl A.2" has been factored out in the equation along with the sample aliquot (S). In Eq. 101A-1, the sample aliquot, S, is introduced directly into the aeration cell for analysis according to the procedure outlined in Section 11.3.1. A dilution factor is required only if it is necessary to bring the sample into the analytical instrument's calibration range.

NOTE: The maximum allowable blank subtraction for the HCl is the lesser of the two following values: (1) the actual blank measured value (analysis Sample No. HCl A.2 blank), or (2) 5% of the Hg content in the combined HCl rinse and digested sample (analysis Sample No. HCl A.2).

$$m_{(\text{ftr})\text{Hg}} = \frac{[C_{(\text{ftr})\text{Hg}} \text{DF} V_{f(\text{ftr})}]}{S} - \frac{[C_{(\text{ftr} \text{bk})\text{Hg}} \text{DF}_{\text{bk}} V_{f(\text{bk})}]}{S_{\text{bk}}} \quad \text{Eq. 101A-2}$$

NOTE: The maximum allowable blank subtraction for the HCl is the lesser of the two following values: (1) the actual blank measured value (analysis Sample No. "A.1 blank"), or (2) 5% of the Hg content in the filtrate (analysis Sample No. "A.1").

$$m_{\text{Hg}} = m_{(\text{HCl})\text{Hg}} + m_{(\text{ftr})\text{Hg}} \quad \text{Eq. 101A-3}$$

12.3 Mercury Emission Rate. Same as Method 101, Section 12.3.

12.4 Determination of Compliance. Same as Method 101, Section 12.4.

### 13.0 Method Performance

13.1 Precision. Based on eight paired-train tests, the intra-laboratory standard deviation was estimated to be  $4.8 \mu\text{g}/\text{ml}$  in the concentration range of 50 to  $130 \mu\text{g}/\text{m}^3$ .

13.2 Bias. [Reserved]

13.3 Range. After initial dilution, the range of this method is 20 to 800 ng Hg/ml. The upper limit can be extended by further dilution of the sample.

14.0 *Pollution Prevention [Reserved]*

15.0 *Waste Management [Reserved]*

16.0 *References*

Same as Section 16.0 of Method 101, with the addition of the following:

1. Mitchell, W.J., *et al.* Test Methods to Determine the Mercury Emissions from Sludge Incineration Plants. U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-600/4-79-058. September 1979.

2. Wilshire, Frank W., *et al.* Reliability Study of the U.S. EPA's Method 101A—Determination of Particulate and Gaseous Mercury Emissions. U.S. Environmental Protection Agency. Research Triangle Park, NC. Report No. 600/D-31/219 AREAL 367, NTIS Acc No. PB91-233361.

3. Memorandum from William J. Mitchell to Roger T. Shigehara discussing the potential safety hazard in Section 7.2 of Method 101A. February 28, 1990.

17.0 *Tables, Diagrams, Flowcharts, And Validation Data [Reserved]*

METHOD 102—DETERMINATION OF PARTICULATE AND GASEOUS MERCURY EMISSIONS FROM CHLOR-ALKALI PLANTS (HYDROGEN STREAMS)

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part and in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, Method 5, and Method 101.

1.0 *Scope and Application*

1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Hg emissions, including both particulate and gaseous Hg, from chlor-alkali plants and other sources (as specified in the regulations) where the carrier-gas stream in the duct or stack is principally hydrogen.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 *Summary of Method*

2.1 Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in acidic iodine monochloride (ICl) solution. The Hg collected (in the mercuric form) is reduced to

elemental Hg, which is then aerated from the solution into an optical cell and measured by atomic absorption spectrophotometry.

### 3.0 *Definitions [Reserved]*

### 4.0 *Interferences*

Same as Method 101, Section 4.2.

### 5.0 *Safety*

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. Same as Method 101, Section 5.2.

5.3 Explosive Mixtures. The sampler must conduct the source test under conditions of utmost safety because hydrogen and air mixtures are explosive. Since the sampling train essentially is leakless, attention to safe operation can be concentrated at the inlet and outlet. If a leak does occur, however, remove the meter box cover to avoid a possible explosive mixture. The following specific precautions are recommended:

5.3.1 Operate only the vacuum pump during the test. The other electrical equipment, e.g., heaters, fans, and timers, normally are not essential to the success of a hydrogen stream test.

5.3.2 Seal the sample port to minimize leakage of hydrogen from the stack.

5.3.3 Vent sampled hydrogen at least 3 m (10 ft) away from the train. This can be accomplished by attaching a 13-mm (0.50-in.) ID Tygon tube to the exhaust from the orifice meter.

NOTE: A smaller ID tubing may cause the orifice meter calibration to be erroneous. Take care to ensure that the exhaust line is not bent or pinched.

### 6.0 *Equipment and Supplies*

Same as Method 101, Section 6.0, with the exception of the following:

6.1 Probe Heating System. Do not use, unless otherwise specified.

6.2 Glass Fiber Filter. Do not use, unless otherwise specified.

### 7.0 *Reagents and Standards*

Same as Method 101, Section 7.0.

### 8.0 *Sample Collection, Preservation, Transport, and Storage*

Same as Method 101, Section 8.0, with the exception of the following:

8.1 Setting of Isokinetic Rates.

8.1.1 If a nomograph is used, take special care in the calculation of the molecular weight of the stack gas and in the setting of the nomograph to maintain isokinetic conditions during sampling (Sections 8.1.1.1 through 8.1.1.3 below).

8.1.1.1 Calibrate the meter box orifice. Use the techniques described in APTD-0576 (see Reference 9 in Section 17.0 of Method 5). Calibration of the orifice meter at flow conditions that simulate the conditions at the source is suggested. Calibration should either be done with hydrogen or with some other gas having similar Reynolds Number so that there is similarity between the Reynolds Numbers during calibration and during sampling.

8.1.1.2 The nomograph described in APTD-0576 cannot be used to calculate the C factor because the nomograph is designed for use when the stack gas dry molecular weight is  $29 \pm 4$ . Instead, the following calculation should be made to determine the proper C factor:

$$C = 0.00154 \Delta H @ C_p^2 T_m \left( \frac{P_s}{P_m} \right) \frac{(1 - B_{ws})^2}{(1 - B_{ws}) + 18 B_{ws}} \quad \text{Eq. 102-1}$$

Where:

$B_{ws}$  = Fraction by volume of water vapor in the stack gas.

$C_p$  = Pitot tube calibration coefficient, dimensionless.

$M_d$  = Dry molecular weight of stack gas, lb/lb-mole.

$P_s$  = Absolute pressure of stack gas, in. Hg.

$P_m$  = Absolute pressure of gas at the meter, in. Hg.

$T_m$  = Absolute temperature of gas at the orifice, °R.

$\Delta H @$  = Meter box calibration factor obtained in Section 8.1.1.1, in. H<sub>2</sub> O.

0.00154 = (in. H<sub>2</sub> O/°R).

NOTE: This calculation is left in English units, and is not converted to metric units because nomographs are based on English units.

8.1.1.3 Set the calculated C factor on the operating nomograph, and select the proper nozzle diameter and K factor as specified in APTD-0576. If the C factor obtained in Section 8.1.1.2 exceeds the values specified on the existing operating nomograph, expand the C scale logarithmically so that the values can be properly located.

8.1.2 If a calculator is used to set isokinetic rates, it is suggested that the isokinetic equation presented in Reference 13 in Section 17.0 of Method 101 be consulted.

8.2 Sampling in Small (<12-in. Diameter) Stacks. When the stack diameter (or equivalent diameter) is less than 12 inches, conventional pitot tube-probe assemblies should not be used. For sampling guidelines, see Reference 14 in Section 17.0 of Method 101.

## 9.0 Quality Control

Same as Method 101, Section 9.0.



### *10.0 Calibration and Standardizations*

Same as Method 101, Section 10.0.

### *11.0 Analytical Procedure*

Same as Method 101, Section 11.0.

### *12.0 Data Analysis and Calculations*

Same as Method 101, Section 12.0.

### *13.0 Method Performance*

Same as Method 101, Section 13.0.

13.1 Analytical Range. After initial dilution, the range of this method is 0.5 to 120 µg Hg/ml. The upper limit can be extended by further dilution of the sample.

### *14.0 Pollution Prevention. [Reserved]*

### *15.0 Waste Management. [Reserved]*

### *16.0 References*

Same as Method 101, Section 16.0.

### *17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]*

## METHOD 103—BERYLLIUM SCREENING METHOD

### *1.0 Scope and Application*

#### *1.1 Analytes.*

Analyte	CAS No.	Sensitivity
Beryllium (Be)	7440-41-7	Dependent upon analytical procedure used.

1.2 Applicability. This procedure details guidelines and requirements for methods acceptable for use in determining Be emissions in ducts or stacks at stationary sources.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

### *2.0 Summary of Method*

2.1 Particulate Be emissions are withdrawn isokinetically from three points in a duct or stack and are collected on a filter. The collected sample is analyzed for Be using an appropriate technique.

### *3.0 Definitions. [Reserved]*

#### 4.0 Interferences. [Reserved]

#### 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hydrochloric Acid (HCl). Highly corrosive and toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

#### 6.0 Equipment and Supplies

6.1 Sample Collection. A schematic of the required sampling train configuration is shown in Figure 103-1 in Section 17.0. The essential components of the train are as follows:

6.1.1 Nozzle. Stainless steel, or equivalent, with sharp, tapered leading edge.

6.1.2 Probe. Sheathed borosilicate or quartz glass tubing.

6.1.3 Filter. Millipore AA, or equivalent, with appropriate filter holder that provides a positive seal against leakage from outside or around the filter. It is suggested that a Whatman 41, or equivalent, be placed immediately against the back side of the Millipore filter as a guard against breakage of the Millipore. Include the backup filter in the analysis. To be equivalent, other filters shall exhibit at least 99.95 percent efficiency (0.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles, and be amenable to the Be analysis procedure. The filter efficiency tests shall be conducted in accordance with ASTM D 2986-71, 78, 95a (incorporated by reference—see § 61.18). Test data from the supplier's quality control program are sufficient for this purpose.

6.1.4 Meter-Pump System. Any system that will maintain isokinetic sampling rate, determine sample volume, and is capable of a sampling rate of greater than 14 lpm (0.5 cfm).

6.2 Measurement of Stack Conditions. The following equipment is used to measure stack conditions:

6.2.1 Pitot Tube. Type S, or equivalent, with a constant coefficient ( $\pm 5$  percent) over the working range.

6.2.2 Inclined Manometer, or Equivalent. To measure velocity head to  $\pm 10$  percent of the minimum value.

6.2.3 Temperature Measuring Device. To measure stack temperature to  $\pm 1.5$  percent of the minimum absolute stack temperature.

6.2.4 Pressure Measuring Device. To measure stack pressure to  $\pm 2.5$  mm Hg (0.1 in. Hg).

6.2.5 Barometer. To measure atmospheric pressure to  $\pm 2.5$  mm Hg (0.1 in. Hg).

6.2.6 Wet and Dry Bulb Thermometers, Drying Tubes, Condensers, or Equivalent. To determine stack gas moisture content to  $\pm 1$  percent.

### 6.3 Sample Recovery.

6.3.1 Probe Cleaning Equipment. Probe brush or cleaning rod at least as long as probe, or equivalent. Clean cotton balls, or equivalent, should be used with the rod.

6.3.2 Leakless Glass Sample Bottles. To contain sample.

6.4 Analysis. All equipment necessary to perform an atomic absorption, spectrographic, fluorometric, chromatographic, or equivalent analysis.

## 7.0 Reagents and Standards

### 7.1 Sample Recovery.

7.1.1 Water. Deionized distilled, to conform to ASTM D 1193-77, 91 (incorporated by reference—see § 61.18), Type 3.

7.1.2 Acetone. Reagent grade.

7.1.3 Wash Acid, 50 Percent (V/V) Hydrochloric Acid (HCl). Mix equal volumes of concentrated HCl and water, being careful to add the acid slowly to the water.

7.2 Analysis. Reagents and standards as necessary for the selected analytical procedure.

## 8.0 Sample Collection, Preservation, Transport, and Storage

Guidelines for source testing are detailed in the following sections. These guidelines are generally applicable; however, most sample sites differ to some degree and temporary alterations such as stack extensions or expansions often are required to insure the best possible sample site. Further, since Be is hazardous, care should be taken to minimize exposure. Finally, since the total quantity of Be to be collected is quite small, the test must be carefully conducted to prevent contamination or loss of sample.

8.1 Selection of a Sampling Site and Number of Sample Runs. Select a suitable sample site that is as close as practicable to the point of atmospheric emission. If possible, stacks smaller than one foot in diameter should not be sampled.

8.1.1 Ideal Sampling Site. The ideal sampling site is at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion or contraction. For rectangular cross sections, use Equation 103-1 in Section 12.2 to determine an equivalent diameter,  $D_e$ .

8.1.2 Alternate Sampling Site. Some sampling situations may render the above sampling site criteria impractical. In such cases, select an alternate site no less than two diameters downstream and one-half diameter upstream from any point of flow disturbance. Additional sample runs are recommended at any sample site not meeting the criteria of Section 8.1.1.

8.1.3 Number of Sample Runs Per Test. Three sample runs constitute a test. Conduct each run at one of three different points. Select three points that proportionately divide the diameter, or are located at 25, 50, and 75 percent of the diameter from the inside wall. For horizontal ducts, sample on a vertical line

through the centroid. For rectangular ducts, sample on a line through the centroid and parallel to a side. If additional sample runs are performed per Section 8.1.2, proportionately divide the duct to accommodate the total number of runs.

8.2 Measurement of Stack Conditions. Using the equipment described in Section 6.2, measure the stack gas pressure, moisture, and temperature to determine the molecular weight of the stack gas. Sound engineering estimates may be made in lieu of direct measurements. Describe the basis for such estimates in the test report.

### 8.3 Preparation of Sampling Train.

8.3.1 Assemble the sampling train as shown in Figure 103-1. It is recommended that all glassware be precleaned by soaking in wash acid for two hours.

8.3.2 Leak check the sampling train at the sampling site. The leakage rate should not be in excess of 1 percent of the desired sample rate.

### 8.4 Sampling Train Operation.

8.4.1 For each run, measure the velocity at the selected sampling point. Determine the isokinetic sampling rate. Record the velocity head and the required sampling rate. Place the nozzle at the sampling point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. At the conclusion of the test, record the sampling rate. Again measure the velocity head at the sampling point. The required isokinetic rate at the end of the period should not have deviated more than 20 percent from that originally calculated. Describe the reason for any deviation beyond 20 percent in the test report.

8.4.2 Sample at a minimum rate of 14 liters/min (0.5 cfm). Obtain samples over such a period or periods of time as are necessary to determine the maximum emissions which would occur in a 24-hour period. In the case of cyclic operations, perform sufficient sample runs so as to allow determination or calculation of the emissions that occur over the duration of the cycle. A minimum sampling time of two hours per run is recommended.

### 8.5 Sample Recovery.

8.5.1 It is recommended that all glassware be precleaned as in Section 8.3. Sample recovery should also be performed in an area free of possible Be contamination. When the sampling train is moved, exercise care to prevent breakage and contamination. Set aside a portion of the acetone used in the sample recovery as a blank for analysis. The total amount of acetone used should be measured for accurate blank correction. Blanks can be eliminated if prior analysis shows negligible amounts.

8.5.2 Remove the filter (and backup filter, if used) and any loose particulate matter from filter holder, and place in a container.

8.5.3 Clean the probe with acetone and a brush or long rod and cotton balls. Wash into the container with the filter. Wash out the filter holder with acetone, and add to the same container.

## 9.0 Quality Control. [Reserved]

## 10.0 Calibration and Standardization

10.1 Sampling Train. As a procedural check, compare the sampling rate regulation with a dry gas meter, spirometer, rotameter (calibrated for prevailing atmospheric conditions), or equivalent, attached to the nozzle inlet of the complete sampling train.

10.2 Analysis. Perform the analysis standardization as suggested by the manufacturer of the instrument, or the procedures for the analytical method in use.

#### 11.0 Analytical Procedure

Make the necessary preparation of samples and analyze for Be. Any currently acceptable method (e.g., atomic absorption, spectrographic, fluorometric, chromatographic) may be used.

#### 12.0 Data Analysis and Calculations

##### 12.1 Nomenclature.

$A_s$  (avg) = Stack area,  $m^2$  ( $ft^2$ ).

$L$  = Length.

$R$  = Be emission rate, g/day.

$V_s$  (avg) = Average stack gas velocity, m/sec (ft/sec).

$V_{total}$  = Total volume of gas sampled,  $m^3$  ( $ft^3$ ).

$W$  = Width.

$W_t$  = Total weight of Be collected, mg.

$10^{-6}$  = Conversion factor, g/ $\mu$ g.

86,400 = Conversion factor, sec/day.

12.2 Calculate the equivalent diameter,  $D_e$ , for a rectangular cross section as follows:

$$D_e = \frac{2 \cdot L \cdot W}{L + W} \quad \text{Eq. 103-1}$$

12.3 Calculate the Be emission rate,  $R$ , in g/day for each stack using Equation 103-2. For cyclic operations, use only the time per day each stack is in operation. The total Be emission rate from a source is the summation of results from all stacks.

$$R = \frac{W_t V_{s(\text{avg})} A_s (86,400) (10^{-6})}{V_{total}} \quad \text{Eq. 103-2}$$

12.4 Test Report. Prepare a test report that includes as a minimum: A detailed description of the sampling train used, results of the procedural check described in Section 10.1 with all data and calculations made, all pertinent data taken during the test, the basis for any estimates made, isokinetic sampling calculations, and emission results. Include a description of the test site, with a block diagram and brief description of the process, location of the sample points in the stack cross section, and stack dimensions and distances from any point of disturbance.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References. [Reserved]

17.0 Tables, Diagrams, Flow Charts, and Validation Data

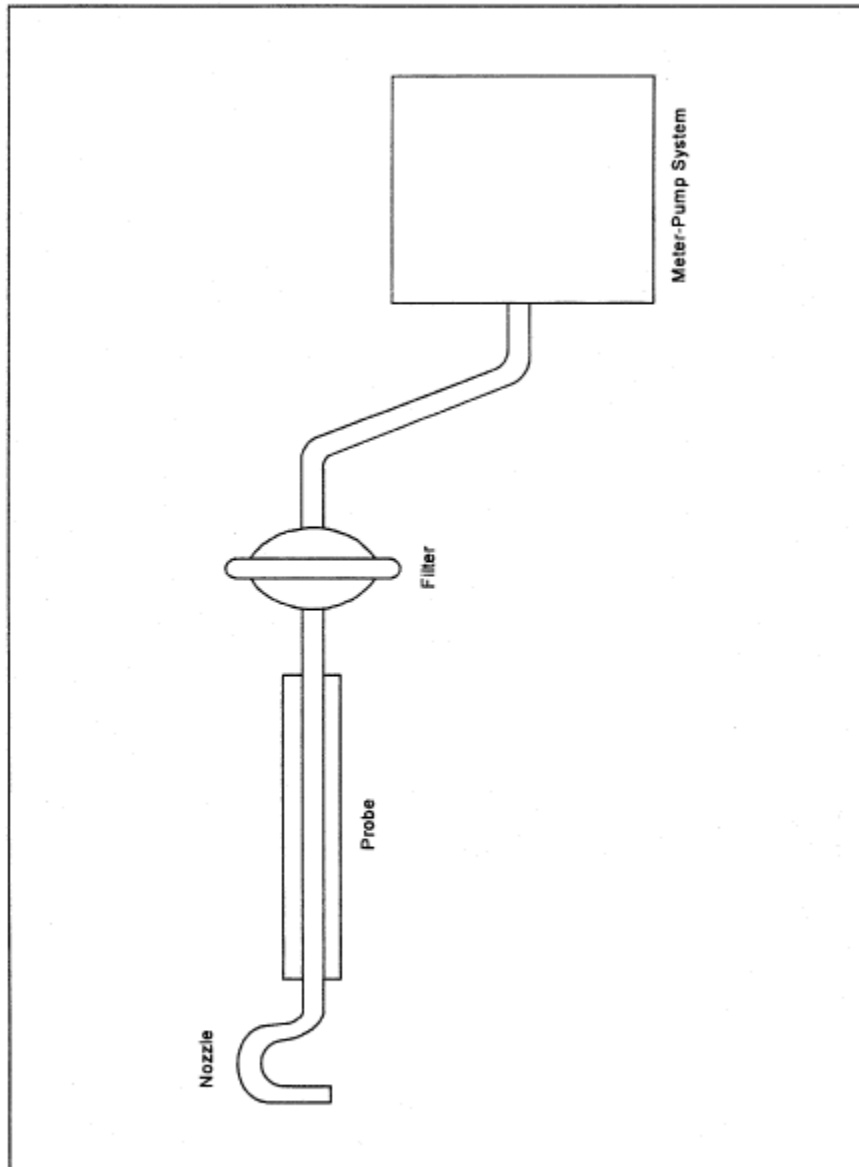


Figure 103-1. Beryllium Screening Method Sampling Train Schematic.

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5 in appendix A, part 60.

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Beryllium (Be)	7440-41-7	Dependent upon recorder and spectrophotometer.

1.2 Applicability. This method is applicable for the determination of Be emissions in ducts or stacks at stationary sources. Unless otherwise specified, this method is not intended to apply to gas streams other than those emitted directly to the atmosphere without further processing.

1.3 Data Quality Objectives. Adherences to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

2.1 Particulate and gaseous Be emissions are withdrawn isokinetically from the source and are collected on a glass fiber filter and in water. The collected sample is digested in an acid solution and is analyzed by atomic absorption spectrophotometry.

## 3.0 Definitions [Reserved]

## 4.0 Interferences

4.1 Matrix Effects. Analysis for Be by flame atomic absorption spectrophotometry is sensitive to the chemical composition and to the physical properties ( e.g., viscosity, pH) of the sample. Aluminum and silicon in particular are known to interfere when present in appreciable quantities. The analytical procedure includes (optionally) the use of the Method of Standard Additions to check for these matrix effects, and sample analysis using the Method of Standard Additions if significant matrix effects are found to be present (see Reference 2 in Section 16.0).

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid (HCl). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to

concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrogen Peroxide ( $H_2O_2$ ). Irritating to eyes, skin, nose, and lungs.

5.2.3 Nitric Acid ( $HNO_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Sodium Hydroxide (NaOH). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with limited amounts of water.

5.3 Beryllium is hazardous, and precautions should be taken to minimize exposure.

## 6.0 *Equipment and Supplies*

6.1 Sample Collection. Same as Method 5, Section 6.1, with the exception of the following:

6.1.1 Sampling Train. Same as Method 5, Section 6.1.1, with the exception of the following:

6.1.2 Probe Liner. Borosilicate or quartz glass tubing. A heating system capable of maintaining a gas temperature of  $120 \pm 14^\circ C$  ( $248 \pm 25^\circ F$ ) at the probe exit during sampling to prevent water condensation may be used.

NOTE: Do not use metal probe liners.

6.1.3 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe. A heating system capable of maintaining the filter at a minimum temperature in the range of the stack temperature may be used to prevent condensation from occurring.

6.1.4 Impingers. Four Greenburg-Smith impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, use impingers that are modified by replacing the tip with a 13 mm-ID (0.5 in.) glass tube extending to 13 mm (0.5 in.) from the bottom of the flask may be used.

6.2 Sample Recovery. The following items are needed for sample recovery:

6.2.1 Probe Cleaning Rod. At least as long as probe.

6.2.2 Glass Sample Bottles. Leakless, with Teflon-lined caps, 1000 ml.

6.2.3 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.

6.2.4 Graduated Cylinder. 250 ml.

6.2.5 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.



6.2.6 Funnel. Glass, to aid in sample recovery.

6.2.7 Plastic Jar. Approximately 300 ml.

6.3 Analysis. The following items are needed for sample analysis:

6.3.1 Atomic Absorption Spectrophotometer. Perkin-Elmer 303, or equivalent, with nitrous oxide/acetylene burner.

6.3.2 Hot Plate.

6.3.3 Perchloric Acid Fume Hood.

## 7.0 Reagents and Standards

NOTE: Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Collection. Same as Method 5, Section 7.1, including deionized distilled water conforming to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 3. The Millipore AA filter is recommended.

7.2 Sample Recovery. Same as Method 5 in appendix A, part 60, Section 7.2, with the addition of the following:

7.2.1 Wash Acid, 50 Percent (V/V) Hydrochloric Acid (HCl). Mix equal volumes of concentrated HCl and water, being careful to add the acid slowly to the water.

7.3 Sample Preparation and Analysis. The following reagents and standards are needed for sample preparation and analysis:

7.3.1 Water. Same as in Section 7.1.

7.3.2. Perchloric Acid ( $\text{HClO}_4$ ). Concentrated (70 percent V/V).

7.3.3 Nitric Acid ( $\text{HNO}_3$ ). Concentrated.

7.3.4 Beryllium Powder. Minimum purity 98 percent.

7.3.5 Sulfuric Acid ( $\text{H}_2\text{SO}_4$ ) Solution, 12 N. Dilute 33 ml of concentrated  $\text{H}_2\text{SO}_4$  to 1 liter with water.

7.3.6 Hydrochloric Acid Solution, 25 Percent HCl (V/V).

7.3.7 Stock Beryllium Standard Solution, 10  $\mu\text{g}$  Be/ml. Dissolve 10.0 mg of Be in 80 ml of 12 N  $\text{H}_2\text{SO}_4$  in a 1000-ml volumetric flask. Dilute to volume with water. This solution is stable for at least one month. Equivalent strength Be stock solutions may be prepared from Be salts such as  $\text{BeCl}_2$  and  $\text{Be}(\text{NO}_3)_2$  (98 percent minimum purity).

7.3.8 Working Beryllium Standard Solution, 1  $\mu\text{g}$  Be/ml. Dilute a 10 ml aliquot of the stock beryllium standard solution to 100 ml with 25 percent HCl solution to give a concentration of 1 mg/ml. Prepare this dilute stock solution fresh daily.

#### 8.0 Sample Collection, Preservation, Transport, and Storage

The amount of Be that is collected is generally small, therefore, it is necessary to exercise particular care to prevent contamination or loss of sample.

8.1 Pretest Preparation. Same as Method 5, Section 8.1, except omit Section 8.1.3.

8.2 Preliminary Determinations. Same as Method 5, Section 8.2, with the exception of the following:

8.2.1 Select a nozzle size based on the range of velocity heads to assure that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

8.2.2 Obtain samples over a period or periods of time that accurately determine the maximum emissions that occur in a 24-hour period. In the case of cyclic operations, perform sufficient sample runs for the accurate determination of the emissions that occur over the duration of the cycle. A minimum sample time of 2 hours per run is recommended.

8.3 Preparation of Sampling Train. Same as Method 5, Section 8.3, with the exception of the following:

8.3.1 Prior to assembly, clean all glassware (probe, impingers, and connectors) by first soaking in wash acid for 2 hours, followed by rinsing with water.

8.3.2 Save a portion of the water for a blank analysis.

8.3.3 Procedures relating to the use of metal probe liners are not applicable.

8.3.4 Probe and filter heating systems are needed only if water condensation is a problem. If this is the case, adjust the heaters to provide a temperature at or above the stack temperature. However, membrane filters such as the Millipore AA are limited to about 107 °C (225 °F). If the stack gas is in excess of about 93 °C (200 °F), consideration should be given to an alternate procedure such as moving the filter holder downstream of the first impinger to insure that the filter does not exceed its temperature limit. After the sampling train has been assembled, turn on and set the probe heating system, if applicable, at the desired operating temperature. Allow time for the temperatures to stabilize. Place crushed ice around the impingers.

NOTE: An empty impinger may be inserted between the third impinger and the silica gel to remove excess moisture from the sample stream.

8.4 Leak Check Procedures, Sampling Train Operation, and Calculation of Percent Isokinetic. Same as Method 5, Sections 8.4, 8.5, and 8.6, respectively.

8.5 Sample Recovery. Same as Method 5, Section 8.7, except treat the sample as follows: Transfer the probe and impinger assembly to a cleanup area that is clean, protected from the wind, and free of Be contamination. Inspect the train before and during this assembly, and note any abnormal conditions. Treat the sample as follows: Disconnect the probe from the impinger train.

8.5.1 Container No. 1. Same as Method 5, Section 8.7.6.1.

8.5.2 Container No. 2. Place the contents (measured to 1 ml) of the first three impingers into a glass sample bottle. Use the procedures outlined in Section 8.7.6.2 of Method 5, where applicable, to rinse the probe nozzle, probe fitting, probe liner, filter holder, and all glassware between the filter holder and the back half of the third impinger with water. Repeat this procedure with acetone. Place both water and acetone rinse solutions in the sample bottle with the contents of the impingers.

8.5.3 Container No. 3. Same as Method 5, Section 8.7.6.3.

8.6 Blanks.

8.6.1 Water Blank. Save a portion of the water as a blank. Take 200 ml directly from the wash bottle being used and place it in a plastic sample container labeled "H<sub>2</sub>O blank."

8.6.2 Filter. Save two filters from each lot of filters used in sampling. Place these filters in a container labeled "filter blank."

8.7 Post-test Glassware Rinsing. If an additional test is desired, the glassware can be carefully double rinsed with water and reassembled. However, if the glassware is out of use more than 2 days, repeat the initial acid wash procedure.

## 9.0 QUALITY CONTROL

Section	Quality control measure	Effect
8.4, 10.1	Sampling equipment leak checks and calibration	Ensure accuracy and precision of sampling measurements.
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminate matrix effects.

### 10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Sampling Equipment. Same as Method 5, Section 10.0.

10.2 Preparation of Standard Solutions. Pipet 1, 3, 5, 8, and 10 ml of the 1.0 µg Be/ml working standard solution into separate 100 ml volumetric flasks, and dilute to the mark with water. The total amounts of Be in these standards are 1, 3, 5, 8, and 10 µg, respectively.

10.3 Spectrophotometer and Recorder. The Be response may be measured by either peak height or peak area. Analyze an aliquot of the 10-µg standard at 234.8 nm using a nitrous oxide/acetylene flame. Determine the maximum absorbance of the standard, and set this value to read 90 percent of the recorder full scale.

10.4 Calibration Curve.

10.4.1 After setting the recorder scale, analyze an appropriately sized aliquot of each standard and the BLANK (see Section 11) until two consecutive peaks agree within 3 percent of their average value.

10.4.3 Subtract the average peak height (or peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak heights of the standards. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Be contamination of a reagent or carry-over of Be from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding total Be weight in the standard (in  $\mu\text{g}$ ).

10.5 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations (i.e., 1, 3, 5, 8, and 10  $\mu\text{g}$  Be) must be less than 7 percent for all standards.

### 11.0 Analytical Procedure

11.1 Sample Loss Check. Prior to analysis, check the liquid level in Container No. 2. Note on the analytical data sheet whether leakage occurred during transport. If a noticeable amount of leakage occurred, either void the sample or take steps, subject to the approval of the Administrator, to adjust the final results.

11.2 Glassware Cleaning. Before use, clean all glassware according to the procedure of Section 8.3.1.

11.3 Sample Preparation. The digestion of Be samples is accomplished in part in concentrated  $\text{HClO}_4$ .

NOTE: The sample must be heated to light brown fumes after the initial  $\text{HNO}_3$  addition; otherwise, dangerous perchlorates may result from the subsequent  $\text{HClO}_4$  digestion.  $\text{HClO}_4$  should be used only under a hood.

11.3.1 Container No. 1. Transfer the filter and any loose particulate matter from Container No. 1 to a 150-ml beaker. Add 35 ml concentrated  $\text{HNO}_3$ . To oxidize all organic matter, heat on a hotplate until light brown fumes are evident. Cool to room temperature, and add 5 ml 12 N  $\text{H}_2\text{SO}_4$  and 5 ml concentrated  $\text{HClO}_4$ .

11.3.2 Container No. 2. Place a portion of the water and acetone sample into a 150 ml beaker, and put on a hotplate. Add portions of the remainder as evaporation proceeds and evaporate to dryness. Cool the residue, and add 35 ml concentrated  $\text{HNO}_3$ . To oxidize all organic matter, heat on a hotplate until light brown fumes are evident. Cool to room temperature, and add 5 ml 12 N  $\text{H}_2\text{SO}_4$  and 5 ml concentrated  $\text{HClO}_4$ . Then proceed with step 11.3.4.

11.3.3 Final Sample Preparation. Add the sample from Section 11.3.2 to the 150-ml beaker from Section 11.3.1. Replace on a hotplate, and evaporate to dryness in a  $\text{HClO}_4$  hood. Cool the residue to room temperature, add 10.0 ml of 25 percent V/V  $\text{HCl}$ , and mix to dissolve the residue.

11.3.4 Filter and Water Blanks. Cut each filter into strips, and treat each filter individually as directed in Section 11.3.1. Treat the 200-ml water blank as directed in Section 11.3.2. Combine and treat these blanks as directed in Section 11.3.3.

11.4 Spectrophotometer Preparation. Turn on the power; set the wavelength, slit width, and lamp current; and adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.5 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.4 and 10.5.

11.5.1 Beryllium Samples. Repeat the procedure used to establish the calibration curve with an appropriately sized aliquot of each sample (from Section 11.3.3) until two consecutive peak heights agree within 3 percent of their average value. The peak height of each sample must be greater than 10 percent of the recorder full scale. If the peak height of the sample is off scale on the recorder, further dilute the original source sample to bring the Be concentration into the calibration range of the spectrophotometer.

11.5.2 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.5.3 Check for Matrix Effects (optional). Use the Method of Standard Additions (see Reference 2 in Section 16.0) to check at least one sample from each source for matrix effects on the Be results. If the results of the Method of Standard Additions procedure used on the single source sample do not agree to within 5 percent of the value obtained by the routine atomic absorption analysis, then reanalyze all samples from the source using the Method of Standard Additions procedure.

11.6 Container No. 2 (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. (This step may be conducted in the field.)

## 12.0 Data Analysis and Calculations

Carry out calculations, retaining at least one extra decimal significant figure beyond that of the acquired data. Round off figures only after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

### 12.1 Nomenclature.

$K_1 = 0.3858$  °K/mm Hg for metric units.

$= 17.64$  °R/in. Hg for English units.

$K_3 = 10^{-6}$  g/ $\mu$ g for metric units.

$= 2.2046 \times 10^{-9}$  lb/ $\mu$ g for English units.

$m_{Be}$  = Total weight of beryllium in the source sample.

$P_s$  = Absolute stack gas pressure, mm Hg (in. Hg).

$t$  = Daily operating time, sec/day.

$T_s$  = Absolute average stack gas temperature, °K (°R).

$V_{m(std)}$  = Dry gas sample volume at standard conditions, scm (scf).

$V_{w(std)}$  = Volume of water vapor at standard conditions, scm (scf).

12.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor Condensed, Moisture Content, Isokinetic Variation, and Stack Gas Velocity and Volumetric Flow Rate. Same as Method 5, Sections 12.2 through 12.5, 12.11, and 12.12, respectively.

12.3 Total Beryllium. For each source sample, correct the average maximum absorbance of the two consecutive samples whose peak heights agree within 3 percent of their average for the contribution of the solution blank (see Sections 11.3.4 and 11.5.2). Correcting for any dilutions if necessary, use the calibration curve and these corrected averages to determine the total weight of Be in each source sample.

12.4 Beryllium Emission Rate. Calculate the daily Hg emission rate, R, using Equation 104-1. For continuous operations, the operating time is equal to 86,400 seconds per day. For cyclic operations, use only the time per day each stack is in operation. The total Hg emission rate from a source will be the summation of results from all stacks.

$$R = \frac{K_1 K_2 t m_{Be} P_s V_s A_s}{T_s (V_{m(sH)} + V_{w(sH)})} \quad \text{Eq. 104-1}$$

12.5 Determination of Compliance. Each performance test consists of three sample runs. For the purpose of determining compliance with an applicable national emission standard, use the average of the results of all sample runs.

13.0 *Method Performance. [Reserved]*

14.0 *Pollution Prevention. [Reserved]*

15.0 *Waste Management. [Reserved]*

16.0 *References*

Same as References 1, 2, and 4-11 of Section 16.0 of Method 101 with the addition of the following:

1. Amos, M.D., and J.B. Willis. Use of High-Temperature Pre-Mixed Flames in Atomic Absorption Spectroscopy. *Spectrochim. Acta.* 22:1325. 1966.

2. Fleet, B., K.V. Liberty, and T. S. West. A Study of Some Matrix Effects in the Determination of Beryllium by Atomic Absorption Spectroscopy in the Nitrous Oxide-Acetylene Flame. *Talanta* 17:203. 1970.

17.0 *Tables, Diagrams, Flowcharts, And Validation Data [Reserved]*

#### METHOD 105—DETERMINATION OF MERCURY IN WASTEWATER TREATMENT PLANT SEWAGE SLUDGES

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should also have a thorough knowledge of at least the following additional test methods: Method 101 and Method 101A.

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Mercury (Hg)	7439-97-6	Dependent upon spectrophotometer and recorder.

1.2 Applicability. This method is applicable for the determination of total organic and inorganic Hg content in sewage sludges.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

2.1 Time-composite sludge samples are withdrawn from the conveyor belt subsequent to dewatering and before incineration or drying. A weighed portion of the sludge is digested in aqua regia and is oxidized by potassium permanganate ( $\text{KMnO}_4$ ). Mercury in the digested sample is then measured by the conventional spectrophotometric cold-vapor technique.

### 3.0 Definitions [Reserved]

### 4.0 Interferences [Reserved]

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burn as thermal burn.

5.2.1 Hydrochloric Acid ( $\text{HCl}$ ). Highly toxic. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Nitric Acid ( $\text{HNO}_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

## 6.0 Equipment and Supplies

6.1 Sample Collection and Mixing. The following items are required for collection and mixing of the sludge samples:

- 6.1.1 Container. Plastic, 50-liter.
- 6.1.2 Scoop. To remove 950-ml (1 quart.) sludge sample.
- 6.1.3 Mixer. Mortar mixer, wheelbarrow-type, 57-liter (or equivalent) with electricity-driven motor.
- 6.1.4 Blender. Waring-type, 2-liter.
- 6.1.5 Scoop. To remove 100-ml and 20-ml samples of blended sludge.
- 6.1.6 Erlenmeyer Flasks. Four, 125-ml.
- 6.1.7 Beakers. Glass beakers in the following sizes: 50 ml (1), 200 ml (1), 400 ml (2).

6.2 Sample Preparation and Analysis. Same as Method 101, Section 6.3, with the addition of the following:

- 6.2.1 Hot Plate.
- 6.2.2 Desiccator.
- 6.2.3 Filter Paper. S and S No. 588 (or equivalent).
- 6.2.4 Beakers. Glass beakers, 200 ml and 400 ml (2 each).

## 7.0 *Reagents and Standards*

NOTE: Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Analysis. Same as Method 101A, Section 7.2, with the following additions and exceptions:

7.1.1 Hydrochloric Acid. The concentrated HCl specified in Method 101A, Section 7.2.4, is not required.

7.1.2 Aqua Regia. Prepare immediately before use. Carefully add one volume of concentrated  $\text{HNO}_3$  to three volumes of concentrated HCl.

## 8.0 *Sample Collection, Preservation, Storage, and Transport*

8.1 Sludge Sampling. Withdraw equal volume increments of sludge [for a total of at least 15 liters (16 quarts)] at intervals of 30 min over an 8-hr period, and combine in a rigid plastic container.

8.2 Sludge Mixing. Transfer the entire 15-liter sample to a mortar mixer. Mix the sample for a minimum of 30 min at 30 rpm. Take six 100-ml portions of sludge, and combine in a 2-liter blender. Blend sludge for 5 min; add water as necessary to give a fluid consistency. Immediately after stopping the blender, withdraw four 20-ml portions of blended sludge, and place them in separate, tared 125-ml Erlenmeyer flasks. Reweigh each flask to determine the exact amount of sludge added.



8.3 Sample Holding Time. Samples shall be analyzed within the time specified in the applicable subpart of the regulations.

#### 9.0 Quality Control

Section	Quality control measure	Effect
10.0	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.0	Check for matrix effects	Eliminate matrix effects.

#### 10.0 Calibration and Standardization

Same as Method 101A, Section 10.2.

#### 11.0 Analytical Procedures

11.1 Solids Content of Blended Sludge. Dry one of the 20-ml blended samples from Section 8.2 in an oven at 105 °C (221 °F) to constant weight. Cool in a desiccator, weigh and record the dry weight of the sample.

#### 11.2 Aqua Regia Digestion of Blended Samples.

11.2.1 To each of the three remaining 20-ml samples from Section 8.2 add 25 ml of aqua regia, and digest the on a hot plate at low heat (do not boil) for 30 min, or until samples are a pale yellow-brown color and are void of the dark brown color characteristic of organic matter. Remove from hotplate and allow to cool.

11.2.2 Filter each digested sample separately through an S and S No. 588 filter or equivalent, and rinse the filter contents with 50 ml of water. Transfer the filtrate and filter washing to a 100-ml volumetric flask, and carefully dilute to volume with water.

11.3 Solids Content of the Sludge Before Blending. Remove two 100-ml portions of mixed sludge from the mortar mixer and place in separate, tared 400-ml beakers. Reweigh each beaker to determine the exact amount of sludge added. Dry in oven at 105 °C (221 °F) and cool in a desiccator to constant weight.

11.4 Analysis for Mercury. Analyze the three aqua regia-digested samples using the procedures outlined in Method 101A, Section 11.0.

#### 12.0 Data Analysis and Calculations

#### 12.1 Nomenclature.

$C_m$  = Concentration of Hg in the digested sample,  $\mu\text{g/g}$ .

$F_{sb}$  = Weight fraction of solids in the blended sludge.

$F_{sm}$  = Weight fraction of solids in the collected sludge after mixing.

$M$  = Hg content of the sewage sludge (on a dry basis),  $\mu\text{g/g}$ .

$m$  = Mass of Hg in the aliquot of digested sample analyzed,  $\mu\text{g}$ .

$n$  = number of digested samples (specified in Section 11.2 as three).

$V_a$  = Volume of digested sample analyzed, ml.

$V_s$  = Volume of digested sample, ml.

$W_b$  = Weight of empty sample beaker, g.

$W_{bs}$  = Weight of sample beaker and sample, g.

$W_{bd}$  = Weight of sample beaker and sample after drying, g.

$W_f$  = Weight of empty sample flask, g.

$W_{fd}$  = Weight of sample flask and sample after drying, g.

$W_{fs}$  = Weight of sample flask and sample, g.

## 12.2 Mercury Content of Digested Sample (Wet Basis).

12.2.1 For each sample analyzed for Hg content, calculate the arithmetic mean maximum absorbance of the two consecutive samples whose peak heights agree  $\pm 3$  percent of their average. Correct this average value for the contribution of the blank. Use the calibration curve and these corrected averages to determine the final Hg concentration in the solution cell for each sludge sample.

12.2.2 Calculate the average Hg concentration of the digested samples by correcting for any dilutions made to bring the sample into the working range of the spectrophotometer and for the weight of the sludge portion digested, using Equation 105-1.

$$\bar{C}_m = \sum_{i=1}^n \left[ \frac{mV_s}{V_a (W_{fs} - W_f)} \right]_i \quad \text{Eq. 105-1}$$

12.3 Solids Content of Blended Sludge. Determine the solids content of the blended sludge using Equation 105-2.

$$F_{sb} = 1 - \frac{W_{fs} - W_{fd}}{W_{fs} - W_f} \quad \text{Eq. 105-2}$$

12.4 Solids Content of Bulk Sample (before blending but, after mixing in mortar mixer). Determine the solids content of each 100 ml aliquot (Section 11.3), and average the results.

$$F_{sm} = 1 - \frac{W_{bs} - W_{bd}}{W_{bs} - W_b} \quad \text{Eq. 105-3}$$

12.5 Mercury Content of Bulk Sample (Dry Basis). Average the results from the three samples from each 8-hr composite sample, and calculate the Hg concentration of the composite sample on a dry basis.

$$M = \frac{\bar{C}_m}{F_{sb}} \quad \text{Eq. 105-4}$$

### 13.0 Method Performance

13.1 Range. The range of this method is 0.2 to 5 micrograms per gram; it may be extended by increasing or decreasing sample size.

### 14.0 Pollution Prevention. [Reserved]

### 15.0 Waste Management. [Reserved]

### 16.0 References

1. Bishop, J.N. Mercury in Sediments. Ontario Water Resources Commission. Toronto, Ontario, Canada. 1971.
2. Salma, M. Private Communication. EPA California/Nevada Basin Office. Alameda, California.
3. Hatch, W.R. and W.L. Ott. Determination of Sub-Microgram Quantities of Mercury by Atomic Absorption Spectrophotometry. Analytical Chemistry. 40:2085. 1968.
4. Bradenberger, H., and H. Bader. The Determination of Nanogram Levels of Mercury in Solution by a Flameless Atomic Absorption Technique. Atomic Absorption Newsletter. 6:101. 1967.
5. Analytical Quality Control Laboratory (AQCL). Mercury in Sediment (Cold Vapor Technique) (Provisional Method). U.S. Environmental Protection Agency. Cincinnati, Ohio. April 1972.
6. Kopp, J.F., M.C. Longbottom, and L.B. Lobring. "Cold Vapor" Method for Determining Mercury. Journal AWWA. 64(1):20-25. 1972.
7. Manual of Methods for Chemical Analysis of Water and Wastes. U.S. Environmental Protection Agency. Cincinnati, Ohio. Publication No. EPA-624/2-74-003. December 1974. pp. 118-138.
8. Mitchell, W.J., M.R. Midgett, J. Suggs, R.J. Velton, and D. Albrink. Sampling and Homogenizing Sewage for Analysis. Environmental Monitoring and Support Laboratory, Office of Research and Development, U.S. Environmental Protection Agency. Research Triangle Park, N.C. March 1979. p. 7.

### 17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]

## METHOD 106—DETERMINATION OF VINYL CHLORIDE EMISSIONS FROM STATIONARY SOURCES

### 1.0 Scope and Application

#### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Vinyl Chloride (CH <sub>2</sub> :CHCl)	75-01-4	Dependent upon analytical equipment.

1.2 Applicability. This method is applicable for the determination of vinyl chloride emissions from ethylene dichloride, vinyl chloride, and polyvinyl chloride manufacturing processes. This method does not measure vinyl chloride contained in particulate matter.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

2.1 An integrated bag sample of stack gas containing vinyl chloride is subjected to GC analysis using a flame ionization detector (FID).

## 3.0 Definitions. [Reserved]

## 4.0 Interferences

4.1 Resolution interferences of vinyl chloride may be encountered on some sources. Therefore, the chromatograph operator should select the column and operating parameters best suited to the particular analysis requirements. The selection made is subject to approval of the Administrator. Approval is automatic, provided that confirming data are produced through an adequate supplemental analytical technique, and that the data are available for review by the Administrator. An example of this would be analysis with a different column or GC/mass spectroscopy.

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Toxic Analyte. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, which is a carcinogen.

## 6.0 Equipment and Supplies

6.1 Sample Collection (see Figure 106-1). The sampling train consists of the following components:

6.1.1 Probe. Stainless steel, borosilicate glass, Teflon tubing (as stack temperature permits), or equivalent, equipped with a glass wool plug to remove particulate matter.

6.1.2 Sample Lines. Teflon, 6.4-mm outside diameter, of sufficient length to connect probe to bag. Use a new unused piece for each series of bag samples that constitutes an emission test, and discard upon completion of the test.

6.1.3 Quick Connects. Stainless steel, male (2) and female (2), with ball checks (one pair without), located as shown in Figure 106-1.

6.1.4 Tedlar Bags. 50- to 100-liter capacity, to contain sample. Aluminized Mylar bags may be used if the samples are analyzed within 24 hours of collection.

6.1.5 Bag Containers. Rigid leak-proof containers for sample bags, with covering to protect contents from sunlight.

6.1.6 Needle Valve. To adjust sample flow rates.

6.1.7 Pump. Leak-free, with minimum of 2-liter/min capacity.

6.1.8 Charcoal Tube. To prevent admission of vinyl chloride and other organics to the atmosphere in the vicinity of samplers.

6.1.9 Flowmeter. For observing sampling flow rate; capable of measuring a flow range from 0.10 to 1.00 liter/min.

6.1.10 Connecting Tubing. Teflon, 6.4-mm outside diameter, to assemble sampling train (Figure 106-1).

6.1.11 Tubing Fittings and Connectors. Teflon or stainless steel, to assemble sampling training.

6.2 Sample Recovery. Teflon tubing, 6.4-mm outside diameter, to connect bag to GC sample loop. Use a new unused piece for each series of bag samples that constitutes an emission test, and discard upon conclusion of analysis of those bags.

6.3 Analysis. The following equipment is required:

6.3.1 Gas Chromatograph. With FID potentiometric strip chart recorder and 1.0 to 5.0-ml heated sampling loop in automatic sample valve. The chromatographic system shall be capable of producing a response to 0.1-ppmv vinyl chloride that is at least as great as the average noise level. (Response is measured from the average value of the base line to the maximum of the wave form, while standard operating conditions are in use.)

6.3.2 Chromatographic Columns. Columns as listed below. Other columns may be used provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and that information is available for review confirming that there is adequate resolution of vinyl chloride peak. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interferent peak. Calculation of area overlap is explained in Procedure 1 of appendix C to this part: "Determination of Adequate Chromatographic Peak Resolution.")

6.3.2.1 Column A. Stainless steel, 2.0 m by 3.2 mm, containing 80/100-mesh Chromasorb 102.

6.3.2.2 Column B. Stainless steel, 2.0 m by 3.2 mm, containing 20 percent GE SF-96 on 60/100-mesh Chromasorb P AW; or stainless steel, 1.0 m by 3.2 mm containing 80/100-mesh Porapak T. Column B is required as a secondary column if acetaldehyde is present. If used, column B is placed after column A. The combined columns should be operated at 120 °C (250 °F).

6.3.3 Rate Meters (2). Rotameter , or equivalent, 100-ml/min capacity, with flow control valves.

6.3.4 Gas Regulators. For required gas cylinders.

6.3.5 Temperature Sensor. Accurate to  $\pm 1$  °C ( $\pm 2$  °F), to measure temperature of heated sample loop at time of sample injection.

6.3.6 Barometer. Accurate to  $\pm 5$  mm Hg, to measure atmospheric pressure around GC during sample analysis.

6.3.7 Pump. Leak-free, with minimum of 100-ml/min capacity.

6.3.8 Recorder. Strip chart type, optionally equipped with either disc or electronic integrator.

6.3.9 Planimeter. Optional, in place of disc or electronic integrator on recorder, to measure chromatograph peak areas.

#### 6.4 Calibration and Standardization.

6.4.1 Tubing. Teflon, 6.4-mm outside diameter, separate pieces marked for each calibration concentration.

NOTE: The following items are required only if the optional standard gas preparation procedures (Section 10.1) are followed.

6.4.2 Tedlar Bags. Sixteen-inch-square size, with valve; separate bag marked for each calibration concentration.

6.4.3 Syringes. 0.5-ml and 50- $\mu$ l, gas tight, individually calibrated to dispense gaseous vinyl chloride.

6.4.4 Dry Gas Meter with Temperature and Pressure Gauges. Singer Model DTM-115 with 802 index, or equivalent, to meter nitrogen in preparation of standard gas mixtures, calibrated at the flow rate used to prepare standards.

### 7.0 Reagents and Standards

7.1 Analysis. The following reagents are required for analysis.

7.1.1 Helium or Nitrogen. Purity 99.9995 percent or greater, for chromatographic carrier gas.

7.1.2 Hydrogen. Purity 99.9995 percent or greater.

7.1.3 Oxygen or Air. Either oxygen (purity 99.99 percent or greater) or air (less than 0.1 ppmv total hydrocarbon content), as required by detector.

7.2 Calibration. Use one of the following options: either Sections 7.2.1 and 7.2.2, or Section 7.2.3.

7.2.1 Vinyl Chloride. Pure vinyl chloride gas certified by the manufacturer to contain a minimum of 99.9 percent vinyl chloride. If the gas manufacturer maintains a bulk cylinder supply of 99.9+ percent vinyl chloride, the certification analysis may have been performed on this supply, rather than on each gas cylinder prepared from this bulk supply. The date of gas cylinder preparation and the certified analysis must have been affixed to the cylinder before shipment from the gas manufacturer to the buyer.

7.2.2 Nitrogen. Same as described in Section 7.1.1.

7.2.3 Cylinder Standards. Gas mixture standards (50-, 10-, and 5 ppmv vinyl chloride) in nitrogen cylinders may be used to directly prepare a chromatograph calibration curve as described in Section 10.3 if the following conditions are met: (a) The manufacturer certifies the gas composition with an accuracy of  $\pm 3$  percent or better. (b) The manufacturer recommends a maximum shelf life over which the gas concentration does not change by greater than  $\pm 5$  percent from the certified value. (c) The manufacturer affixes the date of gas cylinder preparation, certified vinyl chloride concentration, and recommended maximum shelf to the cylinder before shipment to the buyer.

7.2.3.1 Cylinder Standards Certification. The manufacturer shall certify the concentration of vinyl chloride in nitrogen in each cylinder by (a) directly analyzing each cylinder and (b) calibrating his

analytical procedure on the day of cylinder analysis. To calibrate his analytical procedure, the manufacturer shall use as a minimum, a three point calibration curve. It is recommended that the manufacturer maintain (1) a high concentration calibration standard (between 50 and 100 ppmv) to prepare his calibration curve by an appropriate dilution technique and (2) a low-concentration calibration standard (between 5 and 10 ppmv) to verify the dilution technique used. If the difference between the apparent concentration read from the calibration curve and the true concentration assigned to the low-concentration calibration standard exceeds 5 percent of the true concentration, the manufacturer shall determine the source of error and correct it, then repeat the three-point calibration.

7.2.3.2 Verification of Manufacturer's Calibration Standards. Before using a standard, the manufacturer shall verify each calibration standard (a) by comparing it to gas mixtures prepared (with 99 mole percent vinyl chloride) in accordance with the procedure described in Section 7.2.1 or (b) calibrating it against vinyl chloride cylinder Standard Reference Materials (SRM's) prepared by the National Institute of Standards and Technology, if such SRM's are available. The agreement between the initially determined concentration value and the verification concentration value must be  $\pm 5$  percent. The manufacturer must reverify all calibration standards on a time interval consistent with the shelf life of the cylinder standards sold.

#### 8.0 Sample Collection, Preservation, Storage, and Transport

NOTE: Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) nor by those who are unfamiliar with source sampling, because knowledge beyond the scope of this presentation is required.

8.1 Bag Leak-Check. The following leak-check procedure is recommended, but not required, prior to sample collection. The post-test leak-check procedure is mandatory. Connect a water manometer and pressurize the bag to 5 to 10 cm H<sub>2</sub>O (2 to 4 in. H<sub>2</sub>O). Allow to stand for 10 min. Any displacement in the water manometer indicates a leak. Also, check the rigid container for leaks in this manner.

NOTE: An alternative leak-check method is to pressurize the bag to 5 to 10 cm H<sub>2</sub>O and allow it to stand overnight. A deflated bag indicates a leak. For each sample bag in its rigid container, place a rotameter in line between the bag and the pump inlet. Evacuate the bag. Failure of the rotameter to register zero flow when the bag appears to be empty indicates a leak.

8.2 Sample Collection. Assemble the sample train as shown in Figure 106-1. Join the quick connects as illustrated, and determine that all connection between the bag and the probe are tight. Place the end of the probe at the centroid of the stack and start the pump with the needle valve adjusted to yield a flow that will fill over 50 percent of bag volume in the specific sample period. After allowing sufficient time to purge the line several times, change the vacuum line from the container to the bag and evacuate the bag until the rotameter indicates no flow. Then reposition the sample and vacuum lines and begin the actual sampling, keeping the rate proportional to the stack velocity. At all times, direct the gas exiting the rotameter away from sampling personnel. At the end of the sample period, shut off the pump, disconnect the sample line from the bag, and disconnect the vacuum line from the bag container. Protect the bag container from sunlight.

8.3 Sample Storage. Keep the sample bags out of direct sunlight. When at all possible, analysis is to be performed within 24 hours, but in no case in excess of 72 hours of sample collection. Aluminized Mylar bag samples must be analyzed within 24 hours.

8.4 Post-test Bag Leak-Check. Subsequent to recovery and analysis of the sample, leak-check the sample bag according to the procedure outlined in Section 8.1.

## 9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.3	Chromatograph calibration	Ensure precision and accuracy of chromatograph.

### 10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Vinyl Chloride Standard Gas Mixtures. (Optional Procedure-delete if cylinder standards are used.) Evacuate a 16-inch square Tedlar bag that has passed a leak-check (described in Section 8.1) and meter in 5.0 liters of nitrogen. While the bag is filling, use the 0.5-ml syringe to inject 250  $\mu$ l of 99.9+ percent vinyl chloride gas through the wall of the bag. Upon withdrawing the syringe, immediately cover the resulting hole with a piece of adhesive tape. The bag now contains a vinyl chloride concentration of 50 ppmv. In a like manner use the 50  $\mu$ l syringe to prepare gas mixtures having 10-and 5-ppmv vinyl chloride concentrations. Place each bag on a smooth surface and alternately depress opposite sides of the bag 50 times to further mix the gases. These gas mixture standards may be used for 10 days from the date of preparation, after which time new gas mixtures must be prepared. (Caution: Contamination may be a problem when a bag is reused if the new gas mixture standard is a lower concentration than the previous gas mixture standard.)

10.2 Determination of Vinyl Chloride Retention Time. (This section can be performed simultaneously with Section 10.3.) Establish chromatograph conditions identical with those in Section 11.3. Determine proper attenuator position. Flush the sampling loop with helium or nitrogen and activate the sample valve. Record the injection time, sample loop temperature, column temperature, carrier gas flow rate, chart speed, and attenuator setting. Record peaks and detector responses that occur in the absence of vinyl chloride. Maintain conditions with the equipment plumbing arranged identically to Section 11.2, and flush the sample loop for 30 seconds at the rate of 100 ml/min with one of the vinyl chloride calibration mixtures. Then activate the sample valve. Record the injection time. Select the peak that corresponds to vinyl chloride. Measure the distance on the chart from the injection time to the time at which the peak maximum occurs. This quantity divided by the chart speed is defined as the retention time. Since other organics may be present in the sample, positive identification of the vinyl chloride peak must be made.

10.3 Preparation of Chromatograph Calibration Curve. Make a GC measurement of each gas mixture standard (described in Section 7.2.3 or 10.1) using conditions identical to those listed in Sections 11.2 and 11.3. Flush the sampling loop for 30 seconds at the rate of 100 ml/min with one of the standard mixtures, and activate the sample valve. Record the concentration of vinyl chloride injected ( $C_c$ ), attenuator setting, chart speed, peak area, sample loop temperature, column temperature, carrier gas flow rate, and retention time. Record the barometric pressure. Calculate  $A_c$ , the peak area multiplied by the attenuator setting. Repeat until two consecutive injection areas are within 5 percent, then plot the average of those two values versus  $C_c$ . When the other standard gas mixtures have been similarly analyzed and plotted, draw a straight line through the points derived by the least squares method. Perform calibration daily, or before and after the analysis of each emission test set of bag samples, whichever is more frequent. For each group of sample analyses, use the average of the two calibration curves which bracket that group to determine the respective sample concentrations. If the two calibration curves differ by more than 5 percent from their mean value, then report the final results by both calibration curves.

### 11.0 Analytical Procedure

11.2 Sample Recovery. With a new piece of Teflon tubing identified for that bag, connect a bag inlet valve to the gas chromatograph sample valve. Switch the valve to receive gas from the bag through the sample loop. Arrange the equipment so the sample gas passes from the sample valve to 100-ml/min



rotameter with flow control valve followed by a charcoal tube and a 1-in.  $H_2O$  pressure gauge. Maintain the sample flow either by a vacuum pump or container pressurization if the collection bag remains in the rigid container. After sample loop purging is ceased, allow the pressure gauge to return to zero before activating the gas sampling valve.

### 11.3 Analysis.

11.3.1 Set the column temperature to  $100\text{ }^{\circ}\text{C}$  ( $210\text{ }^{\circ}\text{F}$ ) and the detector temperature to  $150\text{ }^{\circ}\text{C}$  ( $300\text{ }^{\circ}\text{F}$ ). When optimum hydrogen and oxygen (or air) flow rates have been determined, verify and maintain these flow rates during all chromatography operations. Using helium or nitrogen as the carrier gas, establish a flow rate in the range consistent with the manufacturer's requirements for satisfactory detector operation. A flow rate of approximately 40 ml/min should produce adequate separations. Observe the base line periodically and determine that the noise level has stabilized and that base line drift has ceased. Purge the sample loop for 30 seconds at the rate of 100 ml/min, shut off flow, allow the sample loop pressure to reach atmospheric pressure as indicated by the  $H_2O$  manometer, then activate the sample valve. Record the injection time (the position of the pen on the chart at the time of sample injection), sample number, sample loop temperature, column temperature, carrier gas flow rate, chart speed, and attenuator setting. Record the barometric pressure. From the chart, note the peak having the retention time corresponding to vinyl chloride as determined in Section 10.2. Measure the vinyl chloride peak area,  $A_m$ , by use of a disc integrator, electronic integrator, or a planimeter. Measure and record the peak heights,  $H_m$ . Record  $A_m$  and retention time. Repeat the injection at least two times or until two consecutive values for the total area of the vinyl chloride peak agree within 5 percent of their average. Use the average value for these two total areas to compute the bag concentration.

11.3.2 Compare the ratio of  $H_m$  to  $A_m$  for the vinyl chloride sample with the same ratio for the standard peak that is closest in height. If these ratios differ by more than 10 percent, the vinyl chloride peak may not be pure (possibly acetaldehyde is present) and the secondary column should be employed (see Section 6.3.2.2).

11.4 Determination of Bag Water Vapor Content. Measure the ambient temperature and barometric pressure near the bag. From a water saturation vapor pressure table, determine and record the water vapor content of the bag,  $B_{wb}$ , as a decimal figure. (Assume the relative humidity to be 100 percent unless a lesser value is known.)

## 12.0 Calculations and Data Analysis

### 12.1 Nomenclature.

$A_m$  = Measured peak area.

$A_f$  = Attenuation factor.

$B_{wb}$  = Water vapor content of the bag sample, as analyzed, volume fraction.

$C_b$  = Concentration of vinyl chloride in the bag, ppmv.

$C_c$  = Concentration of vinyl chloride in the standard sample, ppmv.

$P_i$  = Laboratory pressure at time of analysis, mm Hg.

$P_r$  = Reference pressure, the laboratory pressure recorded during calibration, mm Hg.

$T_i$  = Absolute sample loop temperature at the time of analysis,  $^{\circ}\text{K}$  ( $^{\circ}\text{R}$ ).

$T_r$  = Reference temperature, the sample loop temperature recorded during calibration,  $^{\circ}\text{K}$  ( $^{\circ}\text{R}$ ).

12.2 Sample Peak Area. Determine the sample peak area,  $A_c$ , as follows:

$$A_c = A_m A_f \quad \text{Eq. 106-1}$$

12.3 Vinyl Chloride Concentration. From the calibration curves prepared in Section 10.3, determine the average concentration value of vinyl chloride,  $C_c$ , that corresponds to  $A_c$ , the sample peak area. Calculate the concentration of vinyl chloride in the bag,  $C_b$ , as follows:

$$C_b = \frac{C_c P_r T_i}{P_i T_r (1 - B_{wb})} \quad \text{Eq. 106-2}$$

### 13.0 Method Performance

13.1 Analytical Range. This method is designed for the 0.1 to 50 parts per million by volume (ppmv) range. However, common gas chromatograph (GC) instruments are capable of detecting 0.02 ppmv vinyl chloride. With proper calibration, the upper limit may be extended as needed.

### 14.0 Pollution Prevention, [Reserved]

### 15.0 Waste Management, [Reserved]

### 16.0 References

1. Brown D.W., E.W. Loy, and M.H. Stephenson. Vinyl Chloride Monitoring Near the B. F. Goodrich Chemical Company in Louisville, KY. Region IV, U.S. Environmental Protection Agency, Surveillance and Analysis Division, Athens, GA. June 24, 1974.

2. G.D. Clayton and Associates. Evaluation of a Collection and Analytical Procedure for Vinyl Chloride in Air. U.S. Environmental Protection Agency, Research Triangle Park, N.C. EPA Contract No. 68-02-1408, Task Order No. 2, EPA Report No. 75-VCL-1. December 13, 1974.

3. Midwest Research Institute. Standardization of Stationary Source Emission Method for Vinyl Chloride. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA-600/4-77-026. May 1977.

4. Scheil, G. and M.C. Sharp. Collaborative Testing of EPA Method 106 (Vinyl Chloride) that Will Provide for a Standardized Stationary Source Emission Measurement Method. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA 600/4-78-058. October 1978.

### 17.0 Tables, Diagrams Flowcharts, and Validation Data.

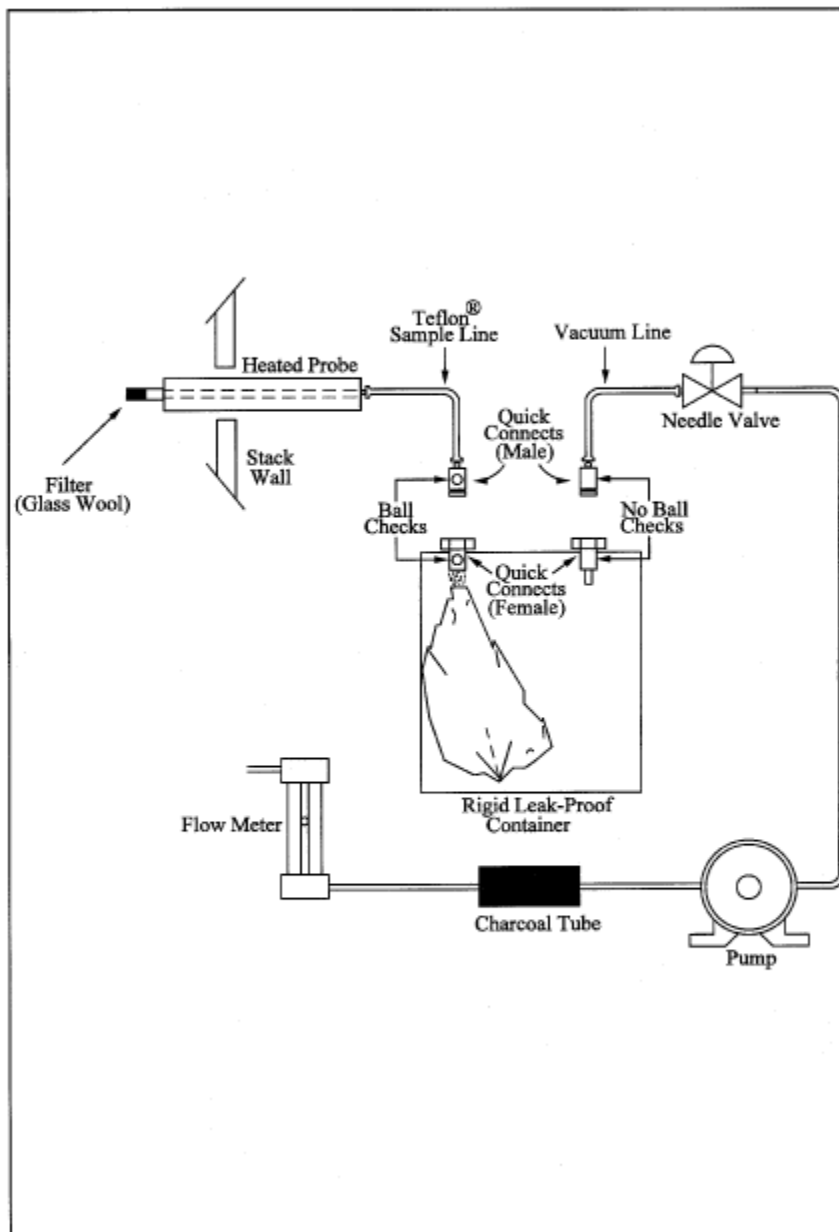


Figure 106-1. Integrated-bag sampling train.

**METHOD 107—DETERMINATION OF VINYL CHLORIDE CONTENT OF IN-PROCESS WASTEWATER SAMPLES, AND VINYL CHLORIDE CONTENT OF POLYVINYL CHLORIDE RESIN SLURRY, WET CAKE, AND LATEX SAMPLES**

NOTE: Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) nor by those who are unfamiliar with source sampling, because knowledge beyond the scope of this presentation is required. This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 106.

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Vinyl Chloride (CH <sub>2</sub> :CHCl)	75-01-4	Dependent upon analytical equipment.

1.2 Applicability. This method is applicable for the determination of the vinyl chloride monomer (VCM) content of in-process wastewater samples, and the residual vinyl chloride monomer (RCVM) content of polyvinyl chloride (PVC) resins, wet, cake, slurry, and latex samples. It cannot be used for polymer in fused forms, such as sheet or cubes. This method is not acceptable where methods from section 304(h) of the Clean Water Act, 33 U.S.C. 1251 *et seq.* (the Federal Water Pollution Control Amendments of 1972 as amended by the Clean Water Act of 1977) are required.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

2.1 The basis for this method relates to the vapor equilibrium that is established at a constant known temperature in a closed system between RVCN, PVC resin, water, and air. The RVCN in a PVC resin will equilibrate rapidly in a closed vessel, provided that the temperature of the PVC resin is maintained above the glass transition temperature of that specific resin.

2.2 A sample of PVC or in-process wastewater is collected in a vial or bottle and is conditioned. The headspace in the vial or bottle is then analyzed for vinyl chloride using gas chromatography with a flame ionization detector.

## 3.0 Definitions [Reserved]

## 4.0 Interferences

4.1 The chromatograph columns and the corresponding operating parameters herein described normally provide an adequate resolution of vinyl chloride; however, resolution interferences may be encountered on some sources. Therefore, the chromatograph operator shall select the column and operating parameters best suited to his particular analysis requirements, subject to the approval of the Administrator. Approval is automatic provided that confirming data are produced through an adequate supplemental analytical technique, such as analysis with a different column or GC/mass spectroscopy, and that these data are made available for review by the Administrator.

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Toxic Analyte. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, which is a carcinogen. Do not release vinyl chloride to the laboratory atmosphere during preparation of standards. Venting or purging with VCM/air mixtures must be held to a minimum. When they are required, the vapor must be routed to outside air. Vinyl chloride, even at low ppm levels, must never be vented inside the laboratory. After vials have been analyzed, the gas must be vented prior to

removal of the vial from the instrument turntable. Vials must be vented through a hypodermic needle connected to an activated charcoal tube to prevent release of vinyl chloride into the laboratory atmosphere. The charcoal must be replaced prior to vinyl chloride breakthrough.

## 6.0 *Equipment and Supplies*

6.1 Sample Collection. The following equipment is required:

6.1.1 Glass bottles. 60-ml (2-oz) capacity, with wax-lined screw-on tops, for PVC samples.

6.1.2 Glass Vials. Headspace vials, with Teflon-faced butyl rubber sealing discs, for water samples.

6.1.3 Adhesive Tape. To prevent loosening of bottle tops.

6.2 Sample Recovery. The following equipment is required:

6.2.1 Glass Vials. Headspace vials, with butyl rubber septa and aluminum caps. Silicone rubber is not acceptable.

6.2.2 Analytical Balance. Capable of determining sample weight within an accuracy of  $\pm 1$  percent.

6.2.3 Vial Sealer. To seal headspace vials.

6.2.4 Syringe. 100-ml capacity.

6.3 Analysis. The following equipment is required:

6.3.1 Headspace Sampler and Chromatograph. Capable of sampling and analyzing a constant amount of headspace gas from a sealed vial, while maintaining that vial at a temperature of  $90\text{ }^{\circ}\text{C} \pm 0.5\text{ }^{\circ}\text{C}$  ( $194\text{ }^{\circ}\text{F} \pm 0.9\text{ }^{\circ}\text{F}$ ). The chromatograph shall be equipped with a flame ionization detector (FID). Perkin-Elmer Corporation Models F-40, F-42, F-45, HS-6, and HS-100, and Hewlett-Packard Corporation Model 19395A have been found satisfactory. Chromatograph backflush capability may be required.

6.3.2 Chromatographic Columns. Stainless steel 1 m by 3.2 mm and 2 m by 3.2 mm, both containing 50/80-mesh Porapak Q. Other columns may be used provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and information confirming that there is adequate resolution of the vinyl chloride peak are available for review. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interferant peak. Calculation of area overlap is explained in Procedure 1 of appendix C to this part: "Determination of Adequate Chromatographic Peak Resolution.") Two 1.83 m columns, each containing 1 percent Carbowax 1500 on Carbowax B, have been found satisfactory for samples containing acetaldehyde.

6.3.3 Temperature Sensor. Range 0 to  $100\text{ }^{\circ}\text{C}$  ( $32$  to  $212\text{ }^{\circ}\text{F}$ ) accurate to  $0.1\text{ }^{\circ}\text{C}$ .

6.3.4 Integrator-Recorder. To record chromatograms.

6.3.5 Barometer. Accurate to 1 mm Hg.

6.3.6 Regulators. For required gas cylinders.

6.3.7 Headspace Vial Pre-Pressurizer. Nitrogen pressurized hypodermic needle inside protective shield.

## 7.0 Reagents and Standards

7.1 Analysis. Same as Method 106, Section 7.1, with the addition of the following:

7.1.1 Water. Interference-free.

7.2 Calibration. The following items are required for calibration:

7.2.1 Cylinder Standards (4). Gas mixture standards (50-, 500-, 2000- and 4000-ppm vinyl chloride in nitrogen cylinders). Cylinder standards may be used directly to prepare a chromatograph calibration curve as described in Section 10.3, if the following conditions are met: (a) The manufacturer certifies the gas composition with an accuracy of  $\pm 3$  percent or better (see Section 7.2.1.1). (b) The manufacturer recommends a maximum shelf life over which the gas concentration does not change by greater than  $\pm 5$  percent from the certified value. (c) The manufacturer affixes the date of gas cylinder preparation, certified vinyl chloride concentration, and recommended maximum shelf life to the cylinder before shipment to the buyer.

7.2.1.1 Cylinder Standards Certification. The manufacturer shall certify the concentration of vinyl chloride in nitrogen in each cylinder by (a) directly analyzing each cylinder and (b) calibrating the analytical procedure on the day of cylinder analysis. To calibrate the analytical procedure, the manufacturer shall use, as a minimum, a 3-point calibration curve. It is recommended that the manufacturer maintain (1) a high-concentration calibration standard (between 4000 and 8000 ppm) to prepare the calibration curve by an appropriate dilution technique and (2) a low-concentration calibration standard (between 50 and 500 ppm) to verify the dilution technique used. If the difference between the apparent concentration read from the calibration curve and the true concentration assigned to the low-concentration calibration standard exceeds 5 percent of the true concentration, the manufacturer shall determine the source of error and correct it, then repeat the 3-point calibration.

7.2.1.2 Verification of Manufacturer's Calibration Standards. Before using, the manufacturer shall verify each calibration standard by (a) comparing it to gas mixtures prepared (with 99 mole percent vinyl chloride) in accordance with the procedure described in Section 10.1 of Method 106 or by (b) calibrating it against vinyl chloride cylinder Standard Reference Materials (SRMs) prepared by the National Institute of Standards and Technology, if such SRMs are available. The agreement between the initially determined concentration value and the verification concentration value must be within 5 percent. The manufacturer must reverify all calibration standards on a time interval consistent with the shelf life of the cylinder standards sold.

## 8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Sample Collection.

8.1.1 PVC Sampling. Allow the resin or slurry to flow from a tap on the tank or silo until the tap line has been well purged. Extend and fill a 60-ml sample bottle under the tap, and immediately tighten a cap on the bottle. Wrap adhesive tape around the cap and bottle to prevent the cap from loosening. Place an identifying label on each bottle, and record the date, time, and sample location both on the bottles and in a log book.

8.1.2 Water Sampling. At the sampling location fill the vials bubble-free to overflowing so that a convex meniscus forms at the top. The excess water is displaced as the sealing disc is carefully placed, with the Teflon side down, on the opening of the vial. Place the aluminum seal over the disc and the neck

of the vial, and crimp into place. Affix an identifying label on the bottle, and record the date, time, and sample location both on the vials and in a log book.

8.2 Sample Storage. All samples must be analyzed within 24 hours of collection, and must be refrigerated during this period.

### 9.0 Quality Control

Section	Quality control measure	Effect
10.3	Chromatograph calibration	Ensure precision and accuracy of chromatograph.

### 10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standards. Calibration standards are prepared as follows: Place 100 µl or about two equal drops of distilled water in the sample vial, then fill the vial with the VCM/nitrogen standard, rapidly seat the septum, and seal with the aluminum cap. Use a  $\frac{1}{8}$ -in. stainless steel line from the cylinder to the vial. Do not use rubber or Tygon tubing. The sample line from the cylinder must be purged (into a properly vented hood) for several minutes prior to filling the vials. After purging, reduce the flow rate to between 500 and 1000 cc/min. Place end of tubing into vial (near bottom). Position a septum on top of the vial, pressing it against the  $\frac{1}{8}$ -in. filling tube to minimize the size of the vent opening. This is necessary to minimize mixing air with the standard in the vial. Each vial is to be purged with standard for 90 seconds, during which time the filling tube is gradually slid to the top of the vial. After the 90 seconds, the tube is removed with the septum, simultaneously sealing the vial. Practice will be necessary to develop good technique. Rubber gloves should be worn during the above operations. The sealed vial must then be pressurized for 60 seconds using the vial prepressurizer. Test the vial for leakage by placing a drop of water on the septum at the needle hole. Prepressurization of standards is not required unless samples have been prepressurized.

10.2 Analyzer Calibration. Calibration is to be performed each 8-hour period the chromatograph is used. Alternatively, calibration with duplicate 50-, 500-, 2,000-, and 4,000-ppm standards (hereafter described as a four-point calibration) may be performed on a monthly basis, provided that a calibration confirmation test consisting of duplicate analyses of an appropriate standard is performed once per plant shift, or once per chromatograph carousel operation (if the chromatograph operation is less frequent than once per shift). The criterion for acceptance of each calibration confirmation test is that both analyses of 500-ppm standards [2,000-ppm standards if dispersion resin (excluding latex resin) samples are being analyzed] must be within 5 percent of the most recent four-point calibration curve. If this criterion is not met, then a complete four-point calibration must be performed before sample analyses can proceed.

10.3 Preparation of Chromatograph Calibration Curve. Prepare two vials each of 50-, 500-, 2,000-, and 4,000-ppm standards. Run the calibration samples in exactly the same manner as regular samples. Plot  $A_s$ , the integrator area counts for each standard sample, versus  $C_c$ , the concentration of vinyl chloride in each standard sample. Draw a straight line through the points derived by the least squares method.

### 11.0 Analytical Procedure

11.1 Preparation of Equipment. Install the chromatographic column and condition overnight at 160 °C (320 °F). In the first operation, Porapak columns must be purged for 1 hour at 230 °C (450 °F).

Do not connect the exit end of the column to the detector while conditioning. Hydrogen and air to the detector must be turned off while the column is disconnected.

## 11.2 Flow Rate Adjustments. Adjust flow rates as follows:

11.2.1. Nitrogen Carrier Gas. Set regulator on cylinder to read 50 psig. Set regulator on chromatograph to produce a flow rate of 30.0 cc/min. Accurately measure the flow rate at the exit end of the column using the soap film flowmeter and a stopwatch, with the oven and column at the analysis temperature. After the instrument program advances to the "B" (backflush) mode, adjust the nitrogen pressure regulator to exactly balance the nitrogen flow rate at the detector as was obtained in the "A" mode.

### 11.2.2. Vial Prepressurizer Nitrogen.

11.2.2.1 After the nitrogen carrier is set, solve the following equation and adjust the pressure on the vial prepressurizer accordingly.

$$P = \frac{T_1}{T_2} \left[ P_1 - \frac{P_{w1} - P_{w2}}{7.50} \right] - 10 \text{ kPa} \quad \text{Eq. 107-1}$$

Where:

$T_1$  = Ambient temperature, °K (°R).

$T_2$  = Conditioning bath temperature, °K (°R).

$P_1$  = Gas chromatograph absolute dosing pressure (analysis mode), k Pa.

$P_{w1}$  = Water vapor pressure 525.8 mm Hg @ 90 °C.

$P_{w2}$  = Water vapor pressure 19.8 mm Hg @ 22 °C.

7.50 = mm Hg per k Pa.

10 kPa = Factor to adjust the prepressurized pressure to slightly less than the dosing pressure.

11.2.2.2 Because of gauge errors, the apparatus may over-pressurize the vial. If the vial pressure is at or higher than the dosing pressure, an audible double injection will occur. If the vial pressure is too low, errors will occur on resin samples because of inadequate time for head-space gas equilibrium. This condition can be avoided by running several standard gas samples at various pressures around the calculated pressure, and then selecting the highest pressure that does not produce a double injection. All samples and standards must be pressurized for 60 seconds using the vial prepressurizer. The vial is then placed into the 90 °C conditioning bath and tested for leakage by placing a drop of water on the septum at the needle hole. A clean, burr-free needle is mandatory.

11.2.3. Burner Air Supply. Set regulator on cylinder to read 50 psig. Set regulator on chromatograph to supply air to burner at a rate between 250 and 300 cc/min. Check with bubble flowmeter.

11.2.4. Hydrogen Supply. Set regulator on cylinder to read 30 psig. Set regulator on chromatograph to supply approximately 35 ±5 cc/min. Optimize hydrogen flow to yield the most sensitive detector response without extinguishing the flame. Check flow with bubble meter and record this flow.

## 11.3 Temperature Adjustments. Set temperatures as follows:

11.3.1. Oven (chromatograph column), 140 °C (280 °F).



11.3.2. Dosing Line, 150 °C (300 °F).

11.3.3. Injection Block, 170 °C (340 °F).

11.3.4. Sample Chamber, Water Temperature, 90 °C  $\pm$ 1.0 °C (194 °F  $\pm$ 1.8 °F).

11.4 Ignition of Flame Ionization Detector. Ignite the detector according to the manufacturer's instructions.

11.5 Amplifier Balance. Balance the amplifier according to the manufacturer's instructions.

11.6 Programming the Chromatograph. Program the chromatograph as follows:

11.6.1. I—Dosing or Injection Time. The normal setting is 2 seconds.

11.6.2. A—Analysis Time. The normal setting is approximately 70 percent of the VCM retention time. When this timer terminates, the programmer initiates backflushing of the first column.

11.6.3. B—Backflushing Time. The normal setting is double the analysis time.

11.6.4. W—Stabilization Time. The normal setting is 0.5 min to 1.0 min.

11.6.5. X—Number of Analyses Per Sample. The normal setting is one.

11.7. Sample Treatment. All samples must be recovered and analyzed within 24 hours after collection.

11.7.1 Resin Samples. The weight of the resin used must be between 0.1 and 4.5 grams. An exact weight must be obtained (within  $\pm$ 1 percent) for each sample. In the case of suspension resins, a volumetric cup can be prepared for holding the required amount of sample. When the cup is used, open the sample bottle, and add the cup volume of resin to the tared sample vial (tared, including septum and aluminum cap). Obtain the exact sample weight, add 100 ml or about two equal drops of water, and immediately seal the vial. Report this value on the data sheet; it is required for calculation of RVCM. In the case of dispersion resins, the cup cannot be used. Weigh the sample in an aluminum dish, transfer the sample to the tared vial, and accurately weigh it in the vial. After prepressurization of the samples, condition them for a minimum of 1 hour in the 90 °C (190 °F) bath. Do not exceed 5 hours. Prepressurization is not required if the sample weight, as analyzed, does not exceed 0.2 gram. It is also not required if solution of the prepressurization equation yields an absolute prepressurization value that is within 30 percent of the atmospheric pressure.

NOTE: Some aluminum vial caps have a center section that must be removed prior to placing into sample tray. If the cap is not removed, the injection needle will be damaged.

11.7.2 Suspension Resin Slurry and Wet Cake Samples. Decant the water from a wet cake sample, and turn the sample bottle upside down onto a paper towel. Wait for the water to drain, place approximately 0.2 to 4.0 grams of the wet cake sample in a tared vial (tared, including septum and aluminum cap) and seal immediately. Then determine the sample weight (1 percent). All samples weighing over 0.2 gram, must be prepressurized prior to conditioning for 1 hour at 90 °C (190 °F), except as noted in Section 11.7.1. A sample of wet cake is used to determine total solids (TS). This is required for calculating the RVCM.

11.7.3 Dispersion Resin Slurry and Geon Latex Samples. The materials should not be filtered. Sample must be thoroughly mixed. Using a tared vial (tared, including septum and aluminum cap) add approximately eight drops (0.25 to 0.35 g) of slurry or latex using a medicine dropper. This should be done immediately after mixing. Seal the vial as soon as possible. Determine sample weight (1 percent). Condition the vial for 1 hour at 90 °C (190 °F) in the analyzer bath. Determine the TS on the slurry sample (Section 11.10).

11.7.4 In-process Wastewater Samples. Using a tared vial (tared, including septum and aluminum cap) quickly add approximately 1 cc of water using a medicine dropper. Seal the vial as soon as possible. Determine sample weight (1 percent). Condition the vial for 1 hour at 90 °C (190 °F) in the analyzer bath.

## 11.8 Preparation of Sample Turntable.

11.8.1 Before placing any sample into turntable, be certain that the center section of the aluminum cap has been removed. The numbered sample vials should be placed in the corresponding numbered positions in the turntable. Insert samples in the following order:

11.8.1.1 Positions 1 and 2. Old 2000-ppm standards for conditioning. These are necessary only after the analyzer has not been used for 24 hours or longer.

11.8.1.2 Position 3. 50-ppm standard, freshly prepared.

11.8.1.3 Position 4. 500-ppm standard, freshly prepared.

11.8.1.4 Position 5. 2000-ppm standard, freshly prepared.

11.8.1.5 Position 6. 4000-ppm standard, freshly prepared.

11.8.1.6 Position 7. Sample No. 7 (This is the first sample of the day, but is given as 7 to be consistent with the turntable and the integrator printout.)

11.8.2 After all samples have been positioned, insert the second set of 50-, 500-, 2000-, and 4000-ppm standards. Samples, including standards, must be conditioned in the bath of 90 °C (190 °F) for a minimum of one hour and a maximum of five hours.

11.9 Start Chromatograph Program. When all samples, including standards, have been conditioned at 90 °C (190 °F) for at least one hour, start the analysis program according to the manufacturer's instructions. These instructions must be carefully followed when starting and stopping a program to prevent damage to the dosing assembly.

11.10 Determination of Total Solids. For wet cake, slurry, resin solution, and PVC latex samples, determine TS for each sample by accurately weighing approximately 3 to 4 grams of sample in an aluminum pan before and after placing in a draft oven (105 to 110 °C (221 to 230 °F)). Samples must be dried to constant weight. After first weighing, return the pan to the oven for a short period of time, and then reweigh to verify complete dryness. The TS are then calculated as the final sample weight divided by initial sample weight.

## 12.0 Calculations and Data Analysis

### 12.1 Nomenclature.

$A_s$  = Chromatogram area counts of vinyl chloride for the sample, area counts.

$A_s$  = Chromatogram area counts of vinyl chloride for the sample.

$C_c$  = Concentration of vinyl chloride in the standard sample, ppm.

$K_p$  = Henry's Law Constant for VCM in PVC 90 °C,  $6.52 \times 10^{-6}$  g/g/mm Hg.

$K_w$  = Henry's Law Constant for VCM in water 90 °C,  $7 \times 10^{-7}$  g/g/mm Hg.

$M_v$  = Molecular weight of VCM, 62.5 g/mole.

$m$  = Sample weight, g.

$P_a$  = Ambient atmospheric pressure, mm Hg.

$R$  = Gas constant, (62360<sup>3</sup> ml) (mm Hg)/(mole)(°K).

$R_f$  = Response factor in area counts per ppm VCM.

$R_s$  = Response factor, area counts/ppm.

$T_1$  = Ambient laboratory temperature, °K.

$TS$  = Total solids expressed as a decimal fraction.

$T_2$  = Equilibrium temperature, °K.

$V_g$  = Volume of vapor phase, ml.

$$= V_v - \frac{m(TS)}{1.36} - \frac{m(1-TS)}{0.9653}$$

$V_v$  = Vial volume, <sup>3</sup> ml.

1.36 = Density of PVC at 90 °C, g/<sup>3</sup> ml.

0.9653 = Density of water at 90 °C, g/<sup>3</sup> ml.

12.2 Response Factor. If the calibration curve described in Section 10.3 passes through zero, an average response factor,  $R_f$ , may be used to facilitate computation of vinyl chloride sample concentrations.

12.2.1 To compute  $R_f$ , first compute a response factor,  $R_s$ , for each sample as follows:

$$R_s = \frac{A_s}{C_c} \quad \text{Eq. 107-2}$$

12.2.2 Sum the individual response factors, and calculate  $R_f$ . If the calibration curve does not pass through zero, use the calibration curve to determine each sample concentration.

12.3 Residual Vinyl Chloride Monomer Concentration, ( $C_{rvc}$ ) or Vinyl Chloride Monomer Concentration. Calculate  $C_{rvc}$  in ppm or mg/kg as follows:

$$C_{rvc} = \frac{A_s P_a}{R_f T_1} \left[ \frac{M_v V_g}{Rm} + K_p (TS) T_2 K_w (1-TS) T_2 \right] \quad \text{Eq. 107-3}$$

NOTE: Results calculated using these equations represent concentration based on the total sample. To obtain results based on dry PVC content, divide by TS.

### 13.0 Method Performance

13.1 Range and Sensitivity. The lower limit of detection of vinyl chloride will vary according to the sampling and chromatographic system. The system should be capable of producing a measurement for a 50-ppm vinyl chloride standard that is at least 10 times the standard deviation of the system background noise level.

13.2 An interlaboratory comparison between seven laboratories of three resin samples, each split into three parts, yielded a standard deviation of 2.63 percent for a sample with a mean of 2.09 ppm, 4.16 percent for a sample with a mean of 1.66 ppm, and 5.29 percent for a sample with a mean of 62.66 ppm.

### 14.0 Pollution Prevention [Reserved]

### 15.0 Waste Management [Reserved]

### 16.0 References

1. B.F. Goodrich, Residual Vinyl Chloride Monomer Content of Polyvinyl Chloride Resins, Latex, Wet Cake, Slurry and Water Samples. B.F. Goodrich Chemical Group Standard Test Procedure No. 1005-E. B.F. Goodrich Technical Center, Avon Lake, Ohio. October 8, 1979.

2. Berens, A.R. The Diffusion of Vinyl Chloride in Polyvinyl Chloride. ACS-Division of Polymer Chemistry, Polymer Preprints 15 (2):197. 1974.

3. Berens, A.R. The Diffusion of Vinyl Chloride in Polyvinyl Chloride. ACS-Division of Polymer Chemistry, Polymer Preprints 15 (2):203. 1974.

4. Berens, A.R., *et. al.* Analysis for Vinyl Chloride in PVC Powders by Head-Space Gas Chromatography. Journal of Applied Polymer Science. 19:3169-3172. 1975.

5. Mansfield, R.A. The Evaluation of Henry's Law Constant (Kp) and Water Enhancement in the Perkin-Elmer Multifract F-40 Gas Chromatograph. B.F. Goodrich. Avon Lake, Ohio. February 10, 1978.

### 17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

METHOD 107A—DETERMINATION OF VINYL CHLORIDE CONTENT OF SOLVENTS, RESIN-SOLVENT SOLUTION, POLYVINYL CHLORIDE RESIN, RESIN SLURRY, WET RESIN, AND LATEX SAMPLES

#### Introduction

Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph (GC) or by those who are unfamiliar with source sampling because knowledge beyond the scope of this presentation is required. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, a carcinogen.

#### 1. Applicability and Principle

1.1 Applicability. This is an alternative method and applies to the measurement of the vinyl chloride content of solvents, resin solvent solutions, polyvinyl chloride (PVC) resin, wet cake slurries, latex, and fabricated resin samples. This method is not acceptable where methods from Section 304(h) of the Clean

Water Act, 33 U.S.C. 1251 *et seq.*, (the Federal Water Pollution Control Act Amendments of 1972 as amended by the Clean Water Act of 1977) are required.

1.2 Principle. The basis for this method lies in the direct injection of a liquid sample into a chromatograph and the subsequent evaporation of all volatile material into the carrier gas stream of the chromatograph, thus permitting analysis of all volatile material including vinyl chloride.

## 2. Range and Sensitivity

The lower limit of detection of vinyl chloride in dry PVC resin is 0.2 ppm. For resin solutions, latexes, and wet resin, this limit rises inversely as the nonvolatile (resin) content decreases.

With proper calibration, the upper limit may be extended as needed.

## 3. Interferences

The chromatograph columns and the corresponding operating parameters herein described normally provide an adequate resolution of vinyl chloride. In cases where resolution interferences are encountered, the chromatograph operator shall select the column and operating parameters best suited to his particular analysis problem, subject to the approval of the Administrator. Approval is automatic, provided that the tester produces confirming data through an adequate supplemental analytical technique, such as analysis with a different column or GC/mass spectroscopy, and has the data available for review by the Administrator.

## 4. Precision and Reproducibility

A standard sample of latex containing 181.8 ppm vinyl chloride analyzed 10 times by the alternative method showed a standard deviation of 7.5 percent and a mean error of 0.21 percent.

A sample of vinyl chloride copolymer resin solution was analyzed 10 times by the alternative method and showed a standard deviation of 6.6 percent at a level of 35 ppm.

## 5. Safety

Do not release vinyl chloride to the laboratory atmosphere during preparation of standards. Venting or purging with vinyl chloride monomer (VCM) air mixtures must be held to minimum. When purging is required, the vapor must be routed to outside air. Vinyl chloride, even at low-ppm levels, must never be vented inside the laboratory.

## 6. Apparatus

6.1 Sampling. The following equipment is required:

6.1.1 Glass Bottles. 16-oz wide mouth wide polyethylene-lined, screw-on tops.

6.1.2 Adhesive Tape. To prevent loosening of bottle tops.

6.2 Sample Recovery. The following equipment is required:

6.2.1 Glass Vials. 20-ml capacity with polycone screw caps.

6.2.2 Analytical Balance. Capable of weighing to  $\pm 0.01$  gram.

6.2.3 Syringe. 50-microliter size, with removable needle.

6.2.4 Fritted Glass Sparger. Fine porosity.

6.2.5 Aluminum Weighing Dishes.

6.2.6 Sample Roller or Shaker. To help dissolve sample.

6.3 Analysis. The following equipment is required:

6.3.1 Gas Chromatograph. Hewlett Packard Model 5720A or equivalent.

6.3.2 Chromatograph Column. Stainless steel, 6.1 m by 3.2 mm, packed with 20 percent Tergitol E-35 on Chromosorb W AW 60/80 mesh. The analyst may use other columns provided that the precision and accuracy of the analysis of vinyl chloride standards are not impaired and that he has available for review information confirming that there is adequate resolution of the vinyl chloride peak. (Adequate resolution is defined as an area overlap of not more than 10 percent of the vinyl chloride peak by an interfering peak. Calculation of area overlap is explained in Appendix C, Procedure 1: "Determination of Adequate Chromatographic Peak Resolution.")

6.3.3 Valco Instrument Six-Port Rotary Valve. For column back flush.

6.3.4 Septa. For chromatograph injection port.

6.3.5 Injection Port Liners. For chromatograph used.

6.3.6 Regulators. For required gas cylinders.

6.3.7 Soap Film Flowmeter. Hewlett Packard No. 0101-0113 or equivalent.

6.4 Calibration. The following equipment is required:

6.4.1 Analytical Balance. Capable of weighing to  $\pm 0.0001$  g.

6.4.2 Erlenmeyer Flask With Glass Stopper. 125 ml.

6.4.3 Pipets. 0.1, 0.5, 1, 5, 10, and 50 ml.

6.4.4 Volumetric Flasks. 10 and 100 ml.

## 7. *Reagents*

Use only reagents that are of chromatograph grade.

7.1 Analysis. The following items are required:

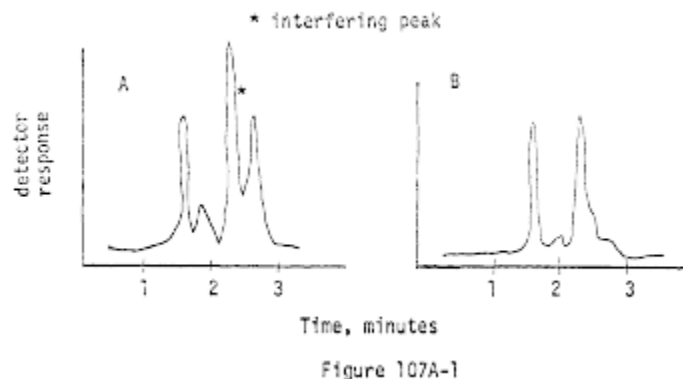
7.1.1 Hydrogen Gas. Zero grade.

7.1.2 Nitrogen Gas. Zero grade.

7.1.3 Air. Zero grade.

#### 7.1.4 Tetrahydrofuran (THF). Reagent grade.

Analyze the THF by injecting 10 microliters into the prepared gas chromatograph. Compare the THF chromatogram with that shown in Figure 107A-1. If the chromatogram is comparable to A, the THF should be sparged with pure nitrogen for approximately 2 hours using the fritted glass sparger to attempt to remove the interfering peak. Reanalyze the sparged THF to determine whether the THF is acceptable for use. If the scan is comparable to B, the THF should be acceptable for use in the analysis.



#### 7.1.5 N, N-Dimethylacetamide (DMAC). Spectrographic grade. For use in place of THF.

#### 7.2 Calibration. The following item is required:

7.2.1 Vinyl Chloride 99.9 Percent. Ideal Gas Products lecture bottle, or equivalent. For preparation of standard solutions.

### 8. Procedure

8.1 Sampling. Allow the liquid or dried resin to flow from a tap on the tank, silo, or pipeline until the tap has been purged. Fill a wide-mouth pint bottle, and immediately tightly cap the bottle. Place an identifying label on each bottle and record the date, time, sample location, and material.

#### 8.2 Sample Treatment. Sample must be run within 24 hours.

8.2.1 Resin Samples. Weigh  $9.00 \pm 0.01$  g of THF or DMAC in a tared 20-ml vial. Add  $1.00 \pm 0.01$  g of resin to the tared vial containing the THF or DMAC. Close the vial tightly with the screw cap, and shake or otherwise agitate the vial until complete solution of the resin is obtained. Shaking may require several minutes to several hours, depending on the nature of the resin.

8.2.2 Suspension Resin Slurry and Wet Resin Sample. Slurry must be filtered using a small Buchner funnel with vacuum to yield a wet resin sample. The filtering process must be continued only as long as a steady stream of water is exiting from the funnel. Excessive filtration time could result in some loss of VCM. The wet resin sample is weighed into a tared 20-ml vial with THF or DMAC as described earlier for resin samples (8.2.1) and treated the same as the resin sample. A sample of the wet resin is used to determine total solids as required for calculating the residual VCM (Section 8.3.4).

8.2.3 Latex and Resin Solvent Solutions. Samples must be thoroughly mixed. Weigh  $1.00 \pm 0.01$  g of the latex or resin-solvent solution into a 20-ml vial containing  $9.00 \pm 0.01$  g of THF or DMAC as for the resin samples (8.2.1). Cap and shake until complete solution is obtained. Determine the total solids of the latex or resin solution sample (Section 8.3.4).

8.2.4 Solvents and Non-viscous Liquid Samples. No preparation of these samples is required. The neat samples are injected directly into the GC.

### 8.3 Analysis.

8.3.1 Preparation of GC. Install the chromatographic column, and condition overnight at 70 °C. Do not connect the exit end of the column to the detector while conditioning.

8.3.1.1 Flow Rate Adjustments. Adjust the flow rate as follows:

a. Nitrogen Carrier Gas. Set regulator on cylinder to read 60 psig. Set column flow controller on the chromatograph using the soap film flowmeter to yield a flow rate of 40 cc/min.

b. Burner Air Supply. Set regulator on the cylinder at 40 psig. Set regulator on the chromatograph to supply air to the burner to yield a flow rate of 250 to 300 cc/min using the flowmeter.

c. Hydrogen. Set regulator on cylinder to read 60 psig. Set regulator on the chromatograph to supply 30 to 40 cc/min using the flowmeter. Optimize hydrogen flow to yield the most sensitive detector response without extinguishing the flame. Check flow with flowmeter and record this flow.

d. Nitrogen Back Flush Gas. Set regulator on the chromatograph using the soap film flowmeter to yield a flow rate of 40 cc/min.

8.3.1.2 Temperature Adjustments. Set temperature as follows:

a. Oven (chromatographic column) at 70 °C.

b. Injection Port at 100 °C.

c. Detector at 300 °C.

8.3.1.3 Ignition of Flame Ionization Detector. Ignite the detector according to the manufacturer's instructions. Allow system to stabilize approximately 1 hour.

8.3.1.4 Recorder. Set pen at zero and start chart drive.

8.3.1.5 Attenuation. Set attenuation to yield desired peak height depending on sample VCM content.

### 8.3.2 Chromatographic Analyses.

a. Sample Injection. Remove needle from 50-microliter syringe. Open sample vial and draw 50-microliters of THF or DMAC sample recovery solution into the syringe. Recap sample vial. Attach needle to the syringe and while holding the syringe vertically (needle uppermost), eject 40 microliters into an absorbent tissue. Wipe needle with tissue. Now inject 10 microliters into chromatograph system. Repeat the injection until two consecutive values for the height of the vinyl chloride peak do not vary more than 5 percent. Use the average value for these two peak heights to compute the sample concentration.

b. Back Flush. After 4 minutes has elapsed after sample injection, actuate the back flush valve to purge the first 4 feet of the chromatographic column of solvent and other high boilers.

c. Sample Data. Record on the chromatograph strip chart the data from the sample label.



d. Elution Time. Vinyl chloride elutes at 2.8 minutes. Acetaldehyde elutes at 3.7 minutes. Analysis is considered complete when chart pen becomes stable. After 5 minutes, reset back flush valve and inject next sample.

#### 8.3.3 Chromatograph Servicing.

- a. Septum. Replace after five sample injections.
- b. Sample Port Liner. Replace the sample port liner with a clean spare after five sample injections.
- c. Chromatograph Shutdown. If the chromatograph has been shut down overnight, rerun one or more samples from the preceding day to test stability and precision prior to starting on the current day's work.

8.3.4 Determination of Total Solids (TS). For wet resin, resin solution, and PVC latex samples, determine the TS for each sample by accurately weighing approximately 3 to 5 grams of sample into a tared aluminum pan. The initial procedure is as follows:

- a. Where water is the major volatile component: Tare the weighing dish, and add 3 to 5 grams of sample to the dish. Weigh to the nearest milligram.
- b. Where volatile solvent is the major volatile component: Transfer a portion of the sample to a 20-ml screw cap vial and cap immediately. Weigh the vial to the nearest milligram. Uncap the vial and transfer a 3- to 5-gram portion of the sample to a tared aluminum weighing dish. Recap the vial and reweigh to the nearest milligram. The vial weight loss is the sample weight.

To continue, place the weighing pan in a 130 °C oven for 1 hour. Remove the dish and allow to cool to room temperature in a desiccator. Weigh the pan to the nearest 0.1 mg. Total solids is the weight of material in the aluminum pan after heating divided by the net weight of sample added to the pan originally times 100.

### 9. Calibration of the Chromatograph

9.1 Preparation of Standards. Prepare a 1 percent by weight (approximate) solution of vinyl chloride in THF or DMAC by bubbling vinyl chloride gas from a cylinder into a tared 125-ml glass-stoppered flask containing THF or DMAC. The weight of vinyl chloride to be added should be calculated prior to this operation, i.e., 1 percent of the weight of THF or DMAC contained in the tared flask. This must be carried out in a laboratory hood. Adjust the vinyl chloride flow from the cylinder so that the vinyl chloride dissolves essentially completely in the THF or DMAC and is not blown to the atmosphere. Take particular care not to volatilize any of the solution. Stopper the flask and swirl the solution to effect complete mixing. Weigh the stoppered flask to nearest 0.1 mg to determine the exact amount of vinyl chloride added.

Pipet 10 ml of the approximately 1 percent solution into a 100-ml glass-stoppered volumetric flask, and add THF or DMAC to fill to the mark. Cap the flask and invert 10 to 20 times. This solution contains approximately 1,000 ppm by weight of vinyl chloride (note the exact concentration).

Pipet 50-, 10-, 5-, 1-, 0.5-, and 0.1-ml aliquots of the approximately 1,000 ppm solution into 10 ml glass stoppered volumetric flasks. Dilute to the mark with THF or DMAC, cap the flasks and invert each 10 to 20 times. These solutions contain approximately 500, 100, 50, 10, 5, and 1 ppm vinyl chloride. Note the exact concentration of each one. These standards are to be kept under refrigeration in stoppered bottles, and must be renewed every 3 months.

## 9.2 Preparation of Chromatograph Calibration Curve.

Obtain the GC for each of the six final solutions prepared in Section 9.1 by using the procedure in Section 8.3.2. Prepare a chart plotting peak height obtained from the chromatogram of each solution versus the known concentration. Draw a straight line through the points derived by the least squares method.

## 10. Calculations

10.1 Response Factor. From the calibration curve described in Section 9.2, select the value of  $C_c$  that corresponds to  $H_c$  for each sample. Compute the response factor,  $R_f$ , for each sample as follows:

$$R_f = \frac{C_c}{H_c} \quad \text{Eq. 107A-1}$$

where:

$R_f$  =Chromatograph response factor, ppm/mm.

$C_c$  =Concentration of vinyl chloride in the standard sample, ppm.

$H_c$  =Peak height of the standard sample, mm.

10.2 Residual vinyl chloride monomer concentration ( $C_{rvc}$ ) or vinyl chloride monomer concentration in resin:

$$C_{rvc} = 10H_s R_f \quad \text{Eq. 107A-2}$$

Where:

$C_{rvc}$  =Concentration of residual vinyl chloride monomer, ppm.

$H_s$  =Peak height of sample, mm.

$R_f$  =Chromatograph response factor.

10.3 Samples containing volatile material, i.e., resin solutions, wet resin, and latexes:

$$C_{rvc} = \frac{H_s R_f (1,000)}{TS} \quad \text{Eq. 107A-3}$$

where:

TS=Total solids in the sample, weight fraction.

10.4 Samples of solvents and in process wastewater:

$$C_{rvc} = \frac{H_s R_f}{0.888} \quad \text{Eq. 107A-4}$$

Where:

0.888=Specific gravity of THF.

## 11. Bibliography

1. Communication from R. N. Wheeler, Jr.; Union Carbide Corporation. Part 61 National Emissions Standards for Hazardous Air Pollutants appendix B, Method 107—Alternate Method, September 19, 1977.

## METHOD 108—DETERMINATION OF PARTICULATE AND GASEOUS ARSENIC EMISSIONS

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, Method 5, and Method 12.

### 1.0 Scope and Application.

#### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 µg/ml or less.

1.2 Applicability. This method is applicable for the determination of inorganic As emissions from stationary sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

### 2.0 Summary of Method

Particulate and gaseous As emissions are withdrawn isokinetically from the source and are collected on a glass mat filter and in water. The collected arsenic is then analyzed by means of atomic absorption spectrophotometry (AAS).

### 3.0 Definitions. [Reserved]

### 4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties ( e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (Section 11.5).

### 5.0 Safety

5.1 This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrogen Peroxide ( $H_2O_2$ ). Very harmful to eyes. 30%  $H_2O_2$  can burn skin, nose, and lungs.

5.2.3 Nitric Acid ( $HNO_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Sodium Hydroxide (NaOH). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with small amounts of water.

## 6.0 Equipment and Supplies

6.1 Sample Collection. A schematic of the sampling train used in performing this method is shown in Figure 108-1; it is similar to the Method 5 sampling train of 40 CFR part 60, appendix A. The following items are required for sample collection:

6.1.1 Probe Nozzle, Probe Liner, Pitot Tube, Differential Pressure Gauge, Filter Holder, Filter Heating System, Temperature Sensor, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 6.1.1.1 to 6.1.1.7, 6.1.1.9, 6.1.2, and 6.1.3, respectively.

6.1.2 Impingers. Four impingers connected in series with leak-free ground-glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, use the Greenburg-Smith design, modified by replacing the tip with a 1.3-cm ID (0.5-in.) glass tube extending to about 1.3 cm (0.5 in.) from the bottom of the flask. For the second impinger, use the Greenburg-Smith design with the standard tip. Modifications (e.g., flexible connections between the impingers, materials other than glass, or flexible vacuum lines to connect the filter holder to the condenser) are subject to the approval of the Administrator.

6.1.3 Temperature Sensor. Place a temperature sensor, capable of measuring temperature to within 1 °C (2 °F), at the outlet of the fourth impinger for monitoring purposes.

6.2 Sample Recovery. The following items are required for sample recovery:

6.2.1 Probe-Liner and Probe-Nozzle Brushes, Petri Dishes, Graduated Cylinder and/or Balance, Plastic Storage Containers, and Funnel and Rubber Policeman. Same as Method 5, Sections 6.2.1 and 6.2.4 to 6.2.8, respectively.

6.2.2 Wash Bottles. Polyethylene (2).

6.2.3 Sample Storage Containers. Chemically resistant, polyethylene or polypropylene for glassware washes, 500- or 1000-ml.

6.3 Analysis. The following items are required for analysis:

6.3.1 Spectrophotometer. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nanometers (nm). For measuring samples having less than 10 µg As/ml, use a vapor generator accessory or a graphite furnace.

6.3.2 Recorder. To match the output of the spectrophotometer.

6.3.3 Beakers. 150 ml.

6.3.4 Volumetric Flasks. Glass 50-, 100-, 200-, 500-, and 1000-ml; and polypropylene, 50-ml.

6.3.5 Balance. To measure within 0.5 g.

6.3.6 Volumetric Pipets. 1-, 2-, 3-, 5-, 8-, and 10-ml.

6.3.7 Oven.

6.3.8 Hot Plate.

## 7.0 *Reagents and Standards*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 The following reagents are required for sample collection:

7.1.1 Filters. Same as Method 5, Section 7.1.1, except that the filters need not be unreactive to SO<sub>2</sub>.

7.1.2 Silica Gel, Crushed Ice, and Stopcock Grease. Same as Method 5, Sections 7.1.2, 7.1.4, and 7.1.5, respectively.

7.1.3 Water. Deionized distilled to meet ASTM D 1193-77 or 91 (incorporated by reference-see § 61.18), Type 3. When high concentrations of organic matter are not expected to be present, the KMnO<sub>4</sub> test for oxidizable organic matter may be omitted.

7.2 Sample Recovery.

7.2.1 0.1 N NaOH. Dissolve 4.00 g of NaOH in about 500 ml of water in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with water.

7.3 Analysis. The following reagents and standards are required for analysis:

7.3.1 Water. Same as Section 7.1.3.

7.3.2 Sodium Hydroxide, 0.1 N. Same as in Section 7.2.1.

7.3.3 Sodium Borohydride ( $\text{NaBH}_4$ ), 5 Percent Weight by Volume (W/V). Dissolve 50.0 g of  $\text{NaBH}_4$  in about 500 ml of 0.1 N NaOH in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with 0.1 N NaOH.

7.3.4 Hydrochloric Acid, Concentrated.

7.3.5 Potassium Iodide (KI), 30 Percent (W/V). Dissolve 300 g of KI in 500 ml of water in a 1 liter volumetric flask. Then, dilute to exactly 1.0 liter with water.

7.3.6 Nitric Acid, Concentrated.

7.3.7 Nitric Acid, 0.8 N. Dilute 52 ml of concentrated  $\text{HNO}_3$  to exactly 1.0 liter with water.

7.3.8 Nitric Acid, 50 Percent by Volume (V/V). Add 50 ml concentrated  $\text{HNO}_3$  to 50 ml water.

7.3.9 Stock Arsenic Standard, 1 mg As/ml. Dissolve 1.3203 g of primary standard grade  $\text{As}_2\text{O}_3$  in 20 ml of 0.1 N NaOH in a 150 ml beaker. Slowly add 30 ml of concentrated  $\text{HNO}_3$ . Heat the resulting solution and evaporate just to dryness. Transfer the residue quantitatively to a 1-liter volumetric flask, and dilute to 1.0 liter with water.

7.3.10 Arsenic Working Solution, 1.0  $\mu\text{g}$  As/ml. Pipet exactly 1.0 ml of stock arsenic standard into an acid-cleaned, appropriately labeled 1-liter volumetric flask containing about 500 ml of water and 5 ml of concentrated  $\text{HNO}_3$ . Dilute to exactly 1.0 liter with water.

7.3.11 Air. Suitable quality for AAS analysis.

7.3.12 Acetylene. Suitable quality for AAS analysis.

7.3.13 Nickel Nitrate, 5 Percent Ni (W/V). Dissolve 24.780 g of nickel nitrate hexahydrate  $[\text{Ni}(\text{NO}_3)_2 \cdot 6\text{H}_2\text{O}]$  in water in a 100-ml volumetric flask, and dilute to 100 ml with water.

7.3.14 Nickel Nitrate, 1 Percent Ni (W/V). Pipet 20 ml of 5 percent nickel nitrate solution into a 100-ml volumetric flask, and dilute to exactly 100 ml with water.

7.3.15 Hydrogen Peroxide, 3 Percent by Volume. Pipet 50 ml of 30 percent  $\text{H}_2\text{O}_2$  into a 500-ml volumetric flask, and dilute to exactly 500 ml with water.

## 8.0 Sample Collection, Preservation, Transport, and Storage

8.1 Pretest Preparation. Follow the general procedure given in Method 5, Section 8.1, except the filter need not be weighed, and the 200 ml of 0.1N NaOH and Container 4 should be tared to within 0.5 g.

8.2 Preliminary Determinations. Follow the general procedure given in Method 5, Section 8.2, except select the nozzle size to maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

8.3 Preparation of Sampling Train. Follow the general procedure given in Method 5, Section 8.3.

8.4 Leak-Check Procedures. Same as Method 5, Section 8.4.

8.5 Sampling Train Operation. Follow the general procedure given in Method 5, Section 8.5, except maintain isokinetic sampling flow rates below 28 liters/min (1.0 cfm). For each run, record the data required on a data sheet similar to the one shown in Figure 108-2.

8.6 Calculation of Percent Isokinetic. Same as Method 5, Section 8.6.

8.7 Sample Recovery. Same as Method 5, Section 8.7, except that 0.1 N NaOH is used as the cleanup solvent instead of acetone and that the impinger water is treated as follows:

8.7.1 Container Number 4 (Impinger Water). Clean each of the first three impingers and connecting glassware in the following manner:

8.7.1.1 Wipe the impinger ball joints free of silicone grease, and cap the joints.

8.7.1.2 Rotate and agitate each of the first two impingers, using the impinger contents as a rinse solution.

8.7.1.3 Transfer the liquid from the first three impingers to Container Number 4. Remove the outlet ball-joint cap, and drain the contents through this opening. Do not separate the impinger parts (inner and outer tubes) while transferring their contents to the container.

8.7.1.4 Weigh the contents of Container No. 4 to within 0.5 g. Record in the log the weight of liquid along with a notation of any color or film observed in the impinger catch. The weight of liquid is needed along with the silica gel data to calculate the stack gas moisture content.

NOTE: Measure and record the total amount of 0.1 N NaOH used for rinsing under Sections 8.7.1.5 and 8.7.1.6.

8.7.1.5 Pour approximately 30 ml of 0.1 NaOH into each of the first two impingers, and agitate the impingers. Drain the 0.1 N NaOH through the outlet arm of each impinger into Container Number 4. Repeat this operation a second time; inspect the impingers for any abnormal conditions.

8.7.1.6 Wipe the ball joints of the glassware connecting the impingers and the back half of the filter holder free of silicone grease, and rinse each piece of glassware twice with 0.1 N NaOH; transfer this rinse into Container Number 4. (DO NOT RINSE or brush the glass-fritted filter support.) Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to identify clearly its contents.

8.8 Blanks.

8.8.1 Sodium Hydroxide. Save a portion of the 0.1 N NaOH used for cleanup as a blank. Take 200 ml of this solution directly from the wash bottle being used and place it in a plastic sample container labeled "NaOH blank."

8.8.2 Water. Save a sample of the water, and place it in a container labeled "H<sub>2</sub> O blank."

8.8.3 Filter. Save two filters from each lot of filters used in sampling. Place these filters in a container labeled "filter blank."

## 9.0 Quality Control

### 9.1 MISCELLANEOUS QUALITY CONTROL MEASURES.

Section	Quality control measure	Effect
8.4, 10.1	Sampling equipment leak-checks and calibration	Ensures accuracy and precision of sampling measurements.
10.4	Spectrophotometer calibration	Ensures linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminates matrix effects.

9.2 Volume Metering System Checks. Same as Method 5, Section 9.2.

### 10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Sampling Equipment. Same as Method 5, Section 10.0.

10.2 Preparation of Standard Solutions.

10.2.1 For the high level procedure, pipet 1, 3, 5, 8, and 10 ml of the 1.0 mg As/ml stock solution into separate 100 ml volumetric flasks, each containing 5 ml of concentrated  $\text{HNO}_3$ . Dilute to the mark with water.

10.2.2 For the low level vapor generator procedure, pipet 1, 2, 3, and 5 ml of 1.0  $\mu\text{g}$  As/ml standard solution into separate reaction tubes. Dilute to the mark with water.

10.2.3 For the low level graphite furnace procedure, pipet 1, 5, 10 and 15 ml of 1.0  $\mu\text{g}$  As/ml standard solution into separate flasks along with 2 ml of the 5 percent nickel nitrate solution and 10 ml of the 3 percent  $\text{H}_2\text{O}_2$  solution. Dilute to the mark with water.

10.3 Calibration Curve. Analyze a 0.8 N  $\text{HNO}_3$  blank and each standard solution according to the procedures outlined in section 11.4.1. Repeat this procedure on each standard solution until two consecutive peaks agree within 3 percent of their average value. Subtract the average peak height (or peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak height of each standard solution. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is As contamination of a reagent or carry-over of As from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total As weight in the solution.

10.4 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations ( e.g., 1, 3, 5, 8, and 10 mg As for the high-level procedure) must be less than 7 percent for all standards.

NOTE: For instruments equipped with direct concentration readout devices, preparation of a standard curve will not be necessary. In all cases, follow calibration and operational procedures in the manufacturers' instruction manual.



## 11.0 Analytical Procedure

11.1 Sample Loss Check. Prior to analysis, check the liquid level in Containers Number 2 and Number 4. Note on the analytical data sheet whether leakage occurred during transport. If a noticeable amount of leakage occurred, either void the sample or take steps, subject to the approval of the Administrator, to adjust the final results.

### 11.2 Sample Preparation.

11.2.1 Container Number 1 (Filter). Place the filter and loose particulate matter in a 150 ml beaker. Also, add the filtered solid material from Container Number 2 (see Section 11.2.2). Add 50 ml of 0.1 N NaOH. Then stir and warm on a hot plate at low heat (do not boil) for about 15 minutes. Add 10 ml of concentrated  $\text{HNO}_3$ , bring to a boil, then simmer for about 15 minutes. Filter the solution through a glass fiber filter. Wash with hot water, and catch the filtrate in a clean 150 ml beaker. Boil the filtrate, and evaporate to dryness. Cool, add 5 ml of 50 percent  $\text{HNO}_3$ , and then warm and stir. Allow to cool. Transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

#### 11.2.2 Container Number 2 (Probe Wash).

11.2.2.1 Filter (using a glass fiber filter) the contents of Container Number 2 into a 200 ml volumetric flask. Combine the filtered (solid) material with the contents of Container Number 1 (Filter).

11.2.2.2 Dilute the filtrate to exactly 200 ml with water. Then pipet 50 ml into a 150 ml beaker. Add 10 ml of concentrated  $\text{HNO}_3$ , bring to a boil, and evaporate to dryness. Allow to cool, add 5 ml of 50 percent  $\text{HNO}_3$ , and then warm and stir. Allow the solution to cool, transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

11.2.3 Container Number 4 (Impinger Solution). Transfer the contents of Container Number 4 to a 500 ml volumetric flask, and dilute to exactly 500-ml with water. Pipet 50 ml of the solution into a 150-ml beaker. Add 10 ml of concentrated  $\text{HNO}_3$ , bring to a boil, and evaporate to dryness. Allow to cool, add 5 ml of 50 percent  $\text{HNO}_3$ , and then warm and stir. Allow the solution to cool, transfer to a 50-ml volumetric flask, dilute to volume with water, and mix well.

11.2.4 Filter Blank. Cut each filter into strips, and treat each filter individually as directed in Section 11.2.1, beginning with the sentence, "Add 50 ml of 0.1 N NaOH."

11.2.5 Sodium Hydroxide and Water Blanks. Treat separately 50 ml of 0.1 N NaOH and 50 ml water, as directed under Section 11.2.3, beginning with the sentence, "Pipet 50 ml of the solution into a 150-ml beaker."

11.3 Spectrophotometer Preparation. Turn on the power; set the wavelength, slit width, and lamp current. Adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.4 Analysis. Calibrate the analytical equipment and develop a calibration curve as outlined in Sections 10.2 through 10.4.

11.4.1 Arsenic Samples. Analyze an appropriately sized aliquot of each diluted sample (from Sections 11.2.1 through 11.2.3) until two consecutive peak heights agree within 3 percent of their average value. If applicable, follow the procedures outlined in Section 11.4.1.1. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 0.8 N  $\text{HNO}_3$  so that the final concentration falls within the range of the curve. Using the calibration curve, determine the arsenic concentration in each sample fraction.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed.

11.4.1.1 Arsenic Determination at Low Concentration. The lower limit of flame AAS is 10 µg As/ml. If the arsenic concentration of any sample is at a lower level, use the graphite furnace or vapor generator which is available as an accessory component. Flame, graphite furnace, or vapor generators may be used for samples whose concentrations are between 10 and 30 µg/ml. Follow the manufacturer's instructions in the use of such equipment.

11.4.1.1.1 Vapor Generator Procedure. Place a sample containing between 0 and 5 µg of arsenic in the reaction tube, and dilute to 15 ml with water. Since there is some trial and error involved in this procedure, it may be necessary to screen the samples by conventional atomic absorption until an approximate concentration is determined. After determining the approximate concentration, adjust the volume of the sample accordingly. Pipet 15 ml of concentrated HCl into each tube. Add 1 ml of 30 percent KI solution. Place the reaction tube into a 50 °C (120 °F) water bath for 5 minutes. Cool to room temperature. Connect the reaction tube to the vapor generator assembly. When the instrument response has returned to baseline, inject 5.0 ml of 5 percent NaBH<sub>4</sub>, and integrate the resulting spectrophotometer signal over a 30-second time period.

11.4.1.1.2 Graphite Furnace Procedure. Dilute the digested sample so that a 5 ml aliquot contains less than 1.5 µg of arsenic. Pipet 5 ml of this digested solution into a 10-ml volumetric flask. Add 1 ml of the 1 percent nickel nitrate solution, 0.5 ml of 50 percent HNO<sub>3</sub>, and 1 ml of the 3 percent hydrogen peroxide and dilute to 10 ml with water. The sample is now ready for analysis.

11.4.1.2 Run a blank (0.8 N HNO<sub>3</sub>) and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.4.1.3 Determine the arsenic concentration in the filter blank (i.e., the average of the two blank values from each lot).

11.4.2 Container Number 3 (Silica Gel). This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g; record this weight.

11.5 Check for matrix effects on the arsenic results. Same as Method 12, Section 11.5.

## 12.0 Data Analysis and Calculations

### 12.1 NOMENCLATURE

B<sub>ws</sub> = Water in the gas stream, proportion by volume.

C<sub>a</sub> = Concentration of arsenic as read from the standard curve, µg/ml.

C<sub>s</sub> = Arsenic concentration in stack gas, dry basis, converted to standard conditions, g/dsm<sup>3</sup> (gr/dscf).

E<sub>a</sub> = Arsenic mass emission rate, g/hr (lb/hr).

F<sub>d</sub> = Dilution factor (equals 1 if the sample has not been diluted).

I = Percent of isokinetic sampling.

$m_{bi}$  = Total mass of all four impingers and contents before sampling, g.

$m_{fi}$  = Total mass of all four impingers and contents after sampling, g.

$m_n$  = Total mass of arsenic collected in a specific part of the sampling train,  $\mu\text{g}$ .

$m_t$  = Total mass of arsenic collected in the sampling train,  $\mu\text{g}$ .

$T_m$  = Absolute average dry gas meter temperature ( see Figure 108-2),  $^{\circ}\text{K}$  ( $^{\circ}\text{R}$ ).

$V_m$  = Volume of gas sample as measured by the dry gas meter, dry basis,  $\text{m}^3$  ( $\text{ft}^3$ ).

$V_{m(\text{std})}$  = Volume of gas sample as measured by the dry gas meter, corrected to standard conditions,  $\text{m}^3$  ( $\text{ft}^3$ ).

$V_n$  = Volume of solution in which the arsenic is contained, ml.

$V_{w(\text{std})}$  = Volume of water vapor collected in the sampling train, corrected to standard conditions,  $\text{m}^3$  ( $\text{ft}^3$ ).

$\Delta H$  = Average pressure differential across the orifice meter ( see Figure 108-2), mm  $\text{H}_2\text{O}$  (in.  $\text{H}_2\text{O}$ ).

12.2 Average Dry Gas Meter Temperatures ( $T_m$ ) and Average Orifice Pressure Drop ( $\Delta H$ ). See data sheet (Figure 108-2).

12.3 Dry Gas Volume. Using data from this test, calculate  $V_{m(\text{std})}$  according to the procedures outlined in Method 5, Section 12.3.

12.4 Volume of Water Vapor.

$$V_{w(\text{std})} = K_2 (m_f - m_{bi}) \quad \text{Eq. 108-1}$$

Where:

$K_2 = 0.001334 \text{ m}^3/\text{g}$  for metric units.

$= 0.047012 \text{ ft}^3/\text{g}$  for English units.

12.5 Moisture Content.

$$B_{ws} = \frac{V_{w(\text{std})}}{V_{m(\text{std})} + V_{w(\text{std})}} \quad \text{Eq. 108-2}$$

12.6 Amount of Arsenic Collected.

12.6.1 Calculate the amount of arsenic collected in each part of the sampling train, as follows:

$$m_n = C_a F_d V_n \quad \text{Eq. 108-3}$$

12.6.2 Calculate the total amount of arsenic collected in the sampling train as follows:

$$m_t = m_{\text{filters}} + m_{\text{probe}} + m_{\text{impingers}} \quad \text{Eq. 108-4}$$

$$- m_{\text{filter blank}} - m_{\text{NaOH blank}} - m_{\text{water blank}}$$

12.7 Calculate the arsenic concentration in the stack gas (dry basis, adjusted to standard conditions) as follows:

$$C_s = K_3 \left( m_t / V_{m(\text{std})} \right) \quad \text{Eq. 108-5}$$

Where:

$K_3 = 10^{-6}$  g/ $\mu$ g for metric units

=  $1.54 \times 10^{-5}$  gr/ $\mu$ g for English units

12.8 Stack Gas Velocity and Volumetric Flow Rate. Calculate the average stack gas velocity and volumetric flow rate using data obtained in this method and the equations in Sections 12.2 and 12.3 of Method 2.

12.9 Pollutant Mass Rate. Calculate the arsenic mass emission rate as follows:

$$E_a = C_s Q_{sd} \quad \text{Eq. 108-6}$$

12.10 Isokinetic Variation. Same as Method 5, Section 12.11.

### 13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS 10  $\mu$ g As/ml. The analytical procedure includes provisions for the use of a graphite furnace or vapor generator for samples with a lower arsenic concentration.

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References.

Same as References 1 through 9 of Method 5, Section 17.0, with the addition of the following:

1. Perkin Elmer Corporation. Analytical Methods for Atomic Absorption Spectrophotometry. 303-0152. Norwalk, Connecticut. September 1976. pp. 5-6.

2. Standard Specification for Reagent Water. In: Annual Book of American Society for Testing and Materials Standards. Part 31: Water, Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, PA. 1974. pp. 40-42.

3. Stack Sampling Safety Manual (Draft). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standard, Research Triangle Park, NC. September 1978.

### 17.0 Tables, Diagrams, Flowcharts, and Validation Data

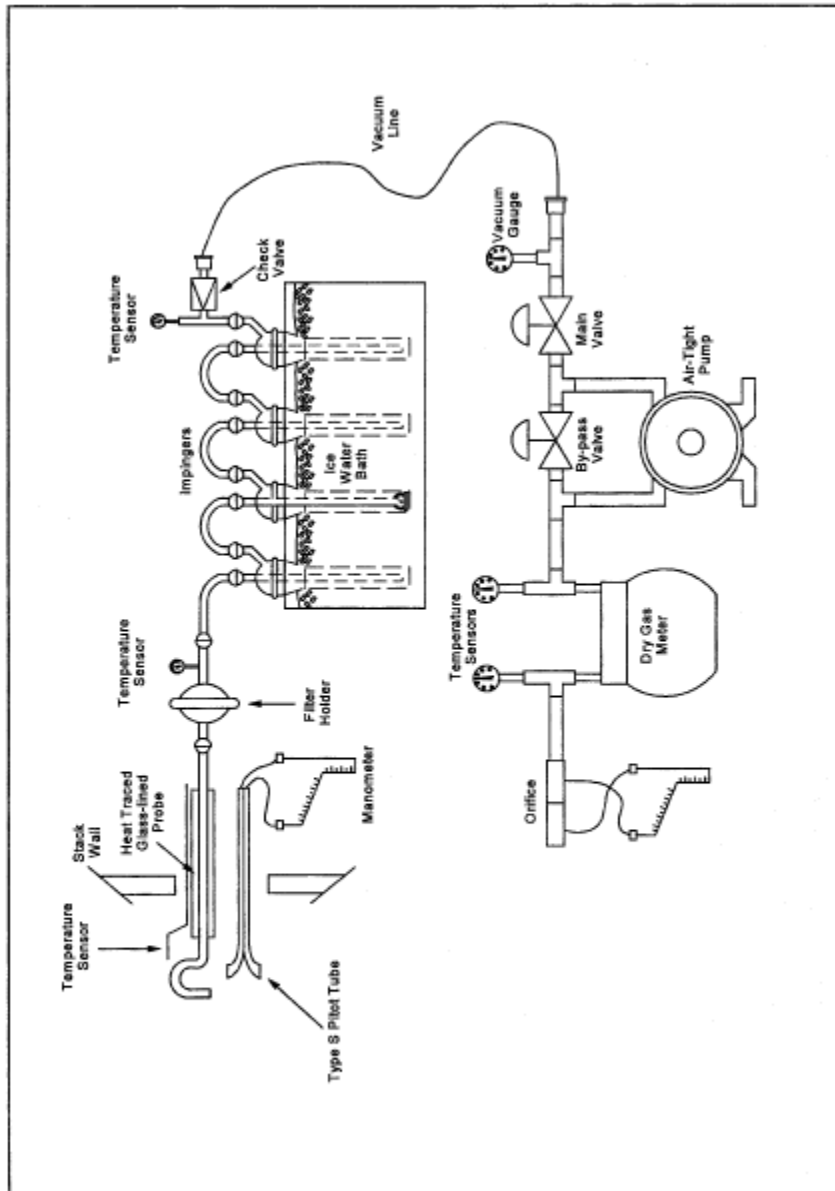


Figure 108-1. Arsenic Sampling Train

Figure 108-2. Arsenic Field Data Sheet.

NOTE: This method does not include all of the specifications ( *e.g.*, equipment and supplies) and procedures ( *e.g.*, sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of Method 12.

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 µg/ml or less.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by flame atomic absorption spectrophotometry (AAS).

## 3.0 Definitions [Reserved]

## 4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties ( e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (section 11.5).

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Hydrogen Peroxide (H<sub>2</sub> O<sub>2</sub> ). Very harmful to eyes. 30% H<sub>2</sub> O<sub>2</sub> can burn skin, nose, and lungs.

5.2.4 Nitric Acid ( $\text{HNO}_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.5 Sodium Hydroxide ( $\text{NaOH}$ ). Causes severe damage to eyes and skin. Inhalation causes irritation to nose, throat, and lungs. Reacts exothermically with limited amounts of water.

## 6.0 *Equipment and Supplies*

6.1 Sample Collection and Preparation. The following items are required for sample collection and preparation:

6.1.1 Parr Acid Digestion Bomb. Stainless steel with vapor-tight Teflon cup and cover.

6.1.2 Volumetric Pipets. 2- and 5-ml sizes.

6.1.3 Volumetric Flask. 50-ml polypropylene with screw caps, (one needed per standard).

6.1.4 Funnel. Polyethylene or polypropylene.

6.1.5 Oven. Capable of maintaining a temperature of approximately 105 °C (221 °F).

6.1.6 Analytical Balance. To measure to within 0.1 mg.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer and Recorder. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nm. For measuring samples having less than 10 µg As/ml, use a graphite furnace or vapor generator accessory. The recorder shall match the output of the spectrophotometer.

6.2.2 Volumetric Flasks. Class A, 50-ml (one needed per sample and blank), 500-ml, and 1-liter.

6.2.3 Volumetric Pipets. Class A, 1-, 5-, 10-, and 25-ml sizes.

## 7.0 *Reagents and Standards.*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Collection and Preparation. The following reagents are required for sample collection and preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—See § 61.18). When high concentrations of organic matter are not expected to be present, the  $\text{KMnO}_4$  test for oxidizable organic matter may be omitted. Use in all dilutions requiring water.

7.1.2 Nitric Acid Concentrated.



7.1.3 Nitric Acid, 0.5 N. In a 1-liter volumetric flask containing water, add 32 ml of concentrated  $\text{HNO}_3$  and dilute to volume with water.

7.1.4 Hydrofluoric Acid, Concentrated.

7.1.5 Potassium Chloride (KCl) Solution, 10 percent weight by volume (W/V). Dissolve 10 g KCl in water, add 3 ml concentrated  $\text{HNO}_3$ , and dilute to 100 ml.

7.1.6 Filter. Teflon filters, 3-micron porosity, 47-mm size. (Available from Millipore Co., type FS, Catalog Number FSLW04700.)

7.1.7 Sodium Borohydride ( $\text{NaBH}_4$ ), 5 Percent (W/V). Dissolve 50.0 g of  $\text{NaBH}_4$  in about 500 ml of 0.1 N NaOH in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with 0.1 N NaOH.

7.1.8 Nickel Nitrate, 5 Percent Ni (W/V). Dissolve 24.780 g of nickel nitrate hexahydrate [ $\text{Ni}(\text{NO}_3)_2 \cdot 6\text{H}_2\text{O}$ ] in water in a 100-ml volumetric flask, and dilute to 100 ml with water.

7.1.9 Nickel Nitrate, 1 Percent Ni (W/V). Pipet 20 ml of 5 percent nickel nitrate solution into a 100-ml volumetric flask, and dilute to 100 ml with water.

7.2 Analysis. The following reagents and standards are required for analysis:

7.2.2 Sodium Hydroxide, 0.1 N. Dissolve 2.00 g of NaOH in water in a 500-ml volumetric flask. Dilute to volume with water.

7.2.3 Nitric Acid, 0.5 N. Same as in Section 7.1.3.

7.2.4 Potassium Chloride Solution, 10 percent. Same as in Section 7.1.5.

7.2.5 Hydrochloric Acid, Concentrated.

7.2.6 Potassium Iodide (KI), 30 Percent (W/V). Dissolve 300 g of KI in about 500 ml of water in a 1-liter volumetric flask. Then, dilute to exactly 1.0 liter with water.

7.2.7 Hydrogen Peroxide, 3 Percent by Volume. Pipet 50 ml of 30 percent  $\text{H}_2\text{O}_2$  into a 500-ml volumetric flask, and dilute to exactly 500 ml with water.

7.2.8 Stock Arsenic Standard, 1 mg As/ml. Dissolve 1.3203 g of primary grade  $\text{As}_2\text{O}_3$  in 20 ml of 0.1 N NaOH. Slowly add 30 ml of concentrated  $\text{HNO}_3$ , and heat in an oven at 105 °C (221 °F) for 2 hours. Allow to cool, and dilute to 1 liter with deionized distilled water.

7.2.9 Nitrous Oxide. Suitable quality for AAS analysis.

7.2.10 Acetylene. Suitable quality for AAS analysis.

7.2.11 Quality Assurance Audit Samples. When making compliance determinations, and upon availability, audit samples may be obtained from the appropriate EPA regional Office or from the responsible enforcement authority.

NOTE: The responsible enforcement authority should be notified at least 30 days prior to the test date to allow sufficient time for sample delivery.

## 8.0 Sample Collection, Preservation, Transport, and Storage

8.1 Sample Collection. A sample that is representative of the ore lot to be tested must be taken prior to analysis. (A portion of the samples routinely collected for metals analysis may be used provided the sample is representative of the ore being tested.)

8.2 Sample Preparation. The sample must be ground into a finely pulverized state.

## 9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.5	Check for matrix effects	Eliminate matrix effects.

### 10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Pipet 1, 5, 10, and 25 ml of the stock As solution into separate 100-ml volumetric flasks. Add 10 ml KCl solution and dilute to the mark with 0.5 N HNO<sub>3</sub>. This will give standard concentrations of 10, 50, 100, and 250 µg As/ml. For low-level arsenic samples that require the use of a graphite furnace or vapor generator, follow the procedures in Section 11.3:1. Dilute 10 ml of KCl solution to 100 ml with 0.5 N HNO<sub>3</sub> and use as a reagent blank.

10.2 Calibration Curve. Analyze the reagent blank and each standard solution according to the procedures outlined in Section 11.3. Repeat this procedure on each standard solution until two consecutive peaks agree within 3 percent of their average value. Subtract the average peak height (or peak area) of the blank—which must be less than 2 percent of recorder full scale—from the averaged peak heights of each standard solution. If the blank absorbance is greater than 2 percent of full-scale, the probable cause is Hg contamination of a reagent or carry-over of As from a previous sample. Prepare the calibration curve by plotting the corrected peak height of each standard solution versus the corresponding final total As weight in the solution.

10.3 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than ±2 percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations must be less than 7 percent for all standards.

NOTE: For instruments equipped with direct concentration readout devices, preparation of a standard curve will not be necessary. In all cases, follow calibration and operational procedures in the manufacturer's instruction manual.

### 11.0 Analytical Procedure

11.1 Sample Preparation. Weigh 50 to 500 mg of finely pulverized sample to the nearest 0.1 mg. Transfer the sample into the Teflon cup of the digestion bomb, and add 2 ml each of concentrated HNO<sub>3</sub> and HF. Seal the bomb immediately to prevent the loss of any volatile arsenic compounds that may form. Heat in an oven at 105 °C (221 °F) for 2 hours. Remove the bomb from the oven and allow to cool. Using a Teflon filter, quantitatively filter the digested sample into a 50-ml polypropylene volumetric flask. Rinse the bomb three times with small portions of 0.5 N HNO<sub>3</sub>, and filter the rinses into the flask. Add 5 ml of KCl solution to the flask, and dilute to 50 ml with 0.5 N HNO<sub>3</sub>.

## 11.2 Spectrophotometer Preparation.

11.2.1 Turn on the power; set the wavelength, slit width, and lamp current. Adjust the background corrector as instructed by the manufacturer's manual for the particular atomic absorption spectrophotometer. Adjust the burner and flame characteristics as necessary.

11.2.2 Develop a spectrophotometer calibration curve as outlined in Sections 10.2 and 10.3.

11.3 Arsenic Determination. Analyze an appropriately sized aliquot of each diluted sample (from Section 11.1) until two consecutive peak heights agree within 3 percent of their average value. If applicable, follow the procedures outlined in Section 11.3.1. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 0.5 N HNO<sub>3</sub> so that the final concentration falls within the range of the curve. Using the calibration curve, determine the As concentration in each sample.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed.

11.3.1 Arsenic Determination at Low Concentration. The lower limit of flame AAS is 10 µg As/ml. If the arsenic concentration of any sample is at a lower level, use the vapor generator or graphite furnace which is available as an accessory component. Flame, graphite furnace, or vapor generators may be used for samples whose concentrations are between 10 and 30 µg/ml. Follow the manufacturer's instructions in the use of such equipment.

11.3.1.1 Vapor Generator Procedure. Place a sample containing between 0 and 5 µg of arsenic in the reaction tube, and dilute to 15 ml with water. Since there is some trial and error involved in this procedure, it may be necessary to screen the samples by conventional AAS until an approximate concentration is determined. After determining the approximate concentration, adjust the volume of the sample accordingly. Pipet 15 ml of concentrated HCl into each tube. Add 1 ml of 30 percent KI solution. Place the reaction tube into a 50 °C (120 °F) water bath for 5 minutes. Cool to room temperature. Connect the reaction tube to the vapor generator assembly. When the instrument response has returned to baseline, inject 5.0 ml of 5 percent NaBH<sub>4</sub> and integrate the resulting spectrophotometer signal over a 30-second time period.

11.3.1.2 Graphite Furnace Procedure. Pipet 5 ml of the digested solution into a 10-ml volumetric flask. Add 1 ml of the 1 percent nickel nitrate solution, 0.5 ml of 50 percent HNO<sub>3</sub>, and 1 ml of the 3 percent H<sub>2</sub>O<sub>2</sub>, and dilute to 10 ml with water. The sample is now ready to inject in the furnace for analysis.

11.4 Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than ±2 percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.5 Mandatory Check for Matrix Effects on the Arsenic Results. Same as Method 12, Section 11.5.

## 12.0 Data Analysis and Calculations

12.1 Calculate the percent arsenic in the ore sample as follows:

$$\% As = \frac{5C_a F_d}{W} \quad \text{Eq. 108A-1}$$

Where:

$C_a$  = Concentration of As as read from the standard curve,  $\mu\text{g/ml}$ .

$F_d$  = Dilution factor (equals to 1 if the sample has not been diluted).

$W$  = Weight of ore sample analyzed, mg.

5 = (50 ml sample " 100)/(10<sup>3</sup>  $\mu\text{g/mg}$ ).

### 13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS is 10  $\mu\text{g As/ml}$ . The analytical procedure includes provisions for the use of a graphite furnace or vapor generator for samples with a lower arsenic concentration.

### 14.0 Pollution Prevention. [Reserved]

### 15.0 Waste Management. [Reserved]

### 16.0 References

Same as References 1 through 9 of Section 17.0 of Method 5, with the addition of the following:

1. Perkin Elmer Corporation. Analytical Methods of Atomic Absorption Spectrophotometry. 303-0152. Norwalk, Connecticut. September 1976. pp 5-6.

2. Ringwald, D. Arsenic Determination on Process Materials from ASARCO's Copper Smelter in Tacoma, Washington. Unpublished Report. Prepared for Emission Measurement Branch, Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. August 1980. 35 pp.

3. Stack Sampling Safety Manual (Draft). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standard, Research Triangle Park, NC. September 1978.

### 17.0 Tables, Diagrams, Flowcharts, and Validation Data. [Reserved]

## METHOD 108B—DETERMINATION OF ARSENIC CONTENT IN ORE SAMPLES FROM NONFERROUS SMELTERS

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this appendix and in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least the following additional test methods: Method 12 and Method 108A.

## 1.0 Scope and Application

### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 10 µg/ml.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations. Samples resulting in an analytical concentration greater than 10 µg As/ml may be analyzed by this method. For lower level arsenic samples, Method 108C should be used.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by flame atomic absorption spectrophotometry (AAS).

## 3.0 Definitions [Reserved]

## 4.0 Interferences

Analysis for As by flame AAS is sensitive to the chemical composition and to the physical properties ( e.g., viscosity, pH) of the sample. The analytical procedure includes a check for matrix effects (Section 11.4).

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid (HNO<sub>3</sub> ). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long

as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid ( $\text{HClO}_4$ ). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Very strong oxidizer. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing  $\text{HClO}_4$  only in hoods specifically designed for  $\text{HClO}_4$ .

## 6.0 *Equipment and Supplies*

6.1 Sample Preparation. The following items are required for sample preparation:

6.1.1 Teflon Beakers. 150-ml.

6.1.2 Graduated Pipets. 5-ml disposable.

6.1.3 Graduated Cylinder. 50-ml.

6.1.4 Volumetric Flask. 100-ml.

6.1.5 Analytical Balance. To measure within 0.1 mg.

6.1.6 Hot Plate.

6.1.7 Perchloric Acid Fume Hood.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer. Equipped with an electrodeless discharge lamp and a background corrector to measure absorbance at 193.7 nm.

6.2.2 Beaker and Watch Glass. 400-ml.

6.2.3 Volumetric Flask. 1-liter.

6.2.4 Volumetric Pipets. 1-, 5-, 10-, and 25-ml.

## 7.0 *Reagents and Standards*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Preparation. The following reagents are required for sample preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—see § 61.18).

7.1.2 Nitric Acid, Concentrated.

7.1.3 Hydrofluoric Acid, Concentrated.

7.1.4 Perchloric Acid, 70 Percent.

7.1.5 Hydrochloric Acid, Concentrated.

7.2 Analysis. The following reagents and standards are required for analysis:

7.2.1 Water. Same as in Section 7.1.1.

7.2.2 Stock Arsenic Standard, 1.0 mg As/ml. Dissolve 1.3203 g of primary grade  $\text{As}_2\text{O}_3$  [dried at 105 °C (221 °F)] in a 400-ml beaker with 10 ml of  $\text{HNO}_3$  and 5 ml of  $\text{HCl}$ . Cover with a watch glass, and heat gently until dissolution is complete. Add 10 ml of  $\text{HNO}_3$  and 25 ml of  $\text{HClO}_4$ , evaporate to strong fumes of  $\text{HClO}_4$ , and reduce to about 20 ml volume. Cool, add 100 ml of water and 100 ml of  $\text{HCl}$ , and transfer quantitatively to a 1-liter volumetric flask. Dilute to volume with water and mix.

7.2.3 Acetylene. Suitable quality for AAS analysis.

7.2.4 Air. Suitable quality for AAS analysis.

#### 8.0 Sample Collection, Preservation, Transport, and Storage

Same as in Method 108A, Sections 8.1 and 8.2.

#### 9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.2	Spectrophotometer calibration	Ensure linearity of spectrophotometer response to standards.
11.4	Check for matrix effects	Eliminate matrix effects.

#### 10.0 Calibration and Standardization

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Pipet 1, 5, 10, and 25 ml of the stock As solution into separate 100-ml volumetric flasks. Add 2 ml of  $\text{HClO}_4$ , 10 ml of  $\text{HCl}$ , and dilute to the mark with water. This will provide standard concentrations of 10, 50, 100, and 250  $\mu\text{g}$  As/ml.

10.2 Calibration Curve and Spectrophotometer Calibration Quality Control. Same as Method 108A, Sections 10.2 and 10.3

#### 11.0 Analytical Procedure

11.1 Sample Preparation. Weigh 100 to 1000 mg of finely pulverized sample to the nearest 0.1 mg. Transfer the sample to a 150-ml Teflon beaker. Dissolve the sample by adding 15 ml of  $\text{HNO}_3$ , 10 ml of  $\text{HCl}$ , 10 ml of  $\text{HF}$ , and 10 ml of  $\text{HClO}_4$  in the exact order as described, and let stand for 10 minutes. In a  $\text{HClO}_4$  fume hood, heat on a hot plate until 2-3 ml of  $\text{HClO}_4$  remain, then cool. Add 20 ml of water and 10 ml of  $\text{HCl}$ . Cover and warm until the soluble salts are in solution. Cool, and transfer quantitatively to a 100-ml volumetric flask. Dilute to the mark with water.

11.2 Spectrophotometer Preparation. Same as in Method 108A, Section 11.2.

11.3 Arsenic Determination. If the sample concentration falls outside the range of the calibration curve, make an appropriate dilution with 2 percent  $\text{HClO}_4$  /10 percent  $\text{HCl}$  (prepared by diluting 2 ml

concentrated  $\text{HClO}_4$  and 10 ml concentrated  $\text{HCl}$  to 100 ml with water) so that the final concentration falls within the range of the curve. Using the calibration curve, determine the As concentration in each sample.

NOTE: Because instruments vary between manufacturers, no detailed operating instructions will be given here. Instead, the instrument manufacturer's detailed operating instructions should be followed.

Run a blank and standard at least after every five samples to check the spectrophotometer calibration. The peak height of the blank must pass through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. The difference between the measured concentration of the standard (the product of the corrected average peak height and the reciprocal of the least squares slope) and the actual concentration of the standard must be less than 7 percent, or recalibration of the analyzer is required.

11.4 Mandatory Check for Matrix Effects on the Arsenic Results. Same as Method 12, Section 11.5.

#### 12.0 Data Analysis and Calculations

Same as in Method 108A, Section 12.0.

#### 13.0 Method Performance

13.1 Sensitivity. The lower limit of flame AAS is 10  $\mu\text{g}$  As/ml.

#### 14.0 Pollution Prevention [Reserved]

#### 15.0 Waste Management [Reserved]

#### 16.0 References

Same as in Method 108A, Section 16.0.

#### 17.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

### METHOD 108C—DETERMINATION OF ARSENIC CONTENT IN ORE SAMPLES FROM NONFERROUS SMELTERS (MOLYBDENUM BLUE PHOTOMETRIC PROCEDURE)

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from other methods in this part. Therefore, to obtain reliable results, persons using this method should have a thorough knowledge of at least Method 108A.

#### 1.0 Scope and Application

##### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Arsenic compounds as arsenic (As)	7440-38-2	Lower limit 0.0002 percent As by weight.

1.2 Applicability. This method applies to the determination of inorganic As content of process ore and reverberatory matte samples from nonferrous smelters and other sources as specified in an applicable subpart of the regulations.



1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

## 2.0 Summary of Method

Arsenic bound in ore samples is liberated by acid digestion and analyzed by the molybdenum blue photometric procedure.

## 3.0 Definitions. [Reserved]

## 4.0 Interferences. [Reserved]

## 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures that prevent chemical splashes are recommended. If contact occurs, immediately flush with copious amounts of water for at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid (HNO<sub>3</sub>). Highly corrosive to eyes, skin, nose, and lungs. Vapors are highly toxic and can cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid (HClO<sub>4</sub>). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Very strong oxidizer. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing HClO<sub>4</sub> only in hoods specifically designed for HClO<sub>4</sub>.

5.2.5 Sulfuric acid (H<sub>2</sub>SO<sub>4</sub>). Rapidly destructive to body tissue. Will cause third degree burns. Eye damage may result in blindness. Inhalation may be fatal from spasm of the larynx, usually within 30 minutes. May cause lung tissue damage with edema. 3 mg/m<sup>3</sup> will cause lung damage in uninitiated. 1 mg/m<sup>3</sup> for 8 hours will cause lung damage or, in higher concentrations, death. Provide ventilation to limit inhalation. Reacts violently with metals and organics.

## 6.0 Equipment and Supplies

6.1 Sample Preparation. The following items are required for sample preparation:

6.1.1 Analytical Balance. To measure to within 0.1 mg.

6.1.2 Erlenmeyer Flask. 300-ml.

6.1.3 Hot Plate.

6.1.4 Distillation Apparatus. No. 6, in ASTM E 50-82, 86, or 90 (Reapproved 1995)(incorporated by reference—see § 61.18); detailed in Figure 108C-1.

6.1.5 Graduated Cylinder. 50-ml.

6.1.6 Perchloric Acid Fume Hood.

6.2 Analysis. The following items are required for analysis:

6.2.1 Spectrophotometer. Capable of measuring at 660 nm.

6.2.2 Volumetric Flasks. 50- and 100-ml.

## 7.0 *Reagents and Standards*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Sample Preparation. The following reagents are required for sample preparation:

7.1.1 Water. Deionized distilled to meet ASTM D 1193-77 or 91 Type 3 (incorporated by reference—see § 61.18). When high concentrations of organic matter are not expected to be present, the  $\text{KMnO}_4$  test for oxidizable organic matter may be omitted. Use in all dilutions requiring water.

7.1.2 Nitric Acid, Concentrated.

7.1.3 Hydrofluoric Acid, Concentrated.

7.1.4 Sulfuric Acid, Concentrated.

7.1.5 Perchloric Acid, 70 Percent.

7.1.6 Hydrochloric Acid, Concentrated.

7.1.7 Dilute Hydrochloric Acid. Add one part concentrated HCl to nine parts water.

7.1.8 Hydrazine Sulfate  $((\text{NH}_2)_2 \cdot \text{H}_2 \text{SO}_4)$ .

7.1.9 Potassium Bromide (KBr).

7.1.10 Bromine Water, Saturated.

7.2 Analysis. The following reagents and standards are required for analysis:

7.2.1 Water. Same as in Section 7.1.1.

7.2.2 Methyl Orange Solution, 1 g/liter.

7.2.3 Ammonium Molybdate Solution, 5 g/liter. Dissolve 0.5 g  $(\text{NH}_4)_2\text{Mo}_7\text{O}_{24} \cdot 4\text{H}_2\text{O}$  in water in a 100-ml volumetric flask, and dilute to the mark. This solution must be freshly prepared.

7.2.4 Standard Arsenic Solution, 10  $\mu\text{g}$  As/ml. Dissolve 0.13203 g of  $\text{As}_2\text{O}_3$  in 100 ml HCl in a 1-liter volumetric flask. Add 200 ml of water, cool, dilute to the mark with water, and mix. Transfer 100 ml of this solution to a 1-liter volumetric flask, add 40 ml HCl, cool, dilute to the mark, and mix.

7.2.5 Hydrazine Sulfate Solution, 1 g/liter. Dissolve 0.1 g of  $(\text{NH}_2)_2 \cdot \text{H}_2\text{SO}_4$  in water, and dilute to 100 ml in a volumetric flask. This solution must be freshly prepared.

7.2.6 Potassium Bromate ( $\text{KBrO}_3$ ) Solution, 0.03 Percent Weight by Volume (W/V). Dissolve 0.3 g  $\text{KBrO}_3$  in water, and dilute to 1 liter with water.

7.2.7 Ammonium Hydroxide ( $\text{NH}_4\text{OH}$ ), Concentrated.

7.2.8 Boiling Granules.

7.2.9 Hydrochloric Acid, 50 percent by volume. Dilute equal parts concentrated HCl with water.

8.0 Sample Collection, Preservation, Transport, and Storage

Same as in Method 108A, Sections 8.1 and 8.2.

9.0 QUALITY CONTROL

Section	Quality control measure	Effect
10.2	Calibration curve preparation	Ensure linearity of spectrophotometric response to standards.

10.0 Calibration and Standardizations

NOTE: Maintain a laboratory log of all calibrations.

10.1 Preparation of Standard Solutions. Transfer 1.0, 2.0, 4.0, 8.0, 12.0, 16.0, and 20.0 ml of standard arsenic solution (10  $\mu\text{g}$ /ml) to each of seven 50-ml volumetric flasks. Dilute to 20 ml with dilute HCl. Add one drop of methyl orange solution and neutralize to the yellow color with dropwise addition of  $\text{NH}_4\text{OH}$ . Just bring back to the red color by dropwise addition of dilute HCl, and add 10 ml in excess. Proceed with the color development as described in Section 11.2.

10.2 Calibration Curve. Plot the spectrophotometric readings of the calibration solutions against  $\mu\text{g}$  As per 50 ml of solution. Use this curve to determine the As concentration of each sample.

10.3 Spectrophotometer Calibration Quality Control. Calculate the least squares slope of the calibration curve. The line must pass through the origin or through a point no further from the origin than  $\pm 2$  percent of the recorder full scale. Multiply the corrected peak height by the reciprocal of the least squares slope to determine the distance each calibration point lies from the theoretical calibration line. The difference between the calculated concentration values and the actual concentrations must be less than 7 percent for all standards.

11.0 Analytical Procedure

## 11.1 Sample Preparation.

11.1.1 Weigh 1.0 g of finely pulverized sample to the nearest 0.1 mg. Transfer the sample to a 300 ml Erlenmeyer flask and add 15 ml of  $\text{HNO}_3$ , 4 ml  $\text{HCl}$ , 2 ml  $\text{HF}$ , 3 ml  $\text{HClO}_4$ , and 15 ml  $\text{H}_2\text{SO}_4$ , in the order listed. In a  $\text{HClO}_4$  fume hood, heat on a hot plate to decompose the sample. Then heat while swirling over an open flame until dense white fumes evolve. Cool, add 15 ml of water, swirl to hydrate the  $\text{H}_2\text{SO}_4$  completely, and add several boiling granules. Cool to room temperature.

11.1.2 Add 1 g of  $\text{KBr}$ , 1 g hydrazine sulfate, and 50 ml  $\text{HCl}$ . Immediately attach the distillation head with thermometer and dip the side arm into a 50-ml graduated cylinder containing 25 ml of water and 2 ml of bromine water. Keep the graduated cylinder immersed in a beaker of cold water during distillation. Distill until the temperature of the vapor in the flask reaches  $107^\circ\text{C}$  ( $225^\circ\text{F}$ ). When distillation is complete, remove the flask from the hot plate, and simultaneously wash down the side arm with water as it is removed from the cylinder.

11.1.3 If the expected arsenic content is in the range of 0.0020 to 0.10 percent, dilute the distillate to the 50-ml mark of the cylinder with water, stopper, and mix. Transfer a 5.0-ml aliquot to a 50-ml volumetric flask. Add 10 ml of water and a boiling granule. Place the flask on a hot plate, and heat gently until the bromine is expelled and the color of methyl orange indicator persists upon the addition of 1 to 2 drops. Cool the flask to room temperature. Neutralize just to the yellow color of the indicator with dropwise additions of  $\text{NH}_4\text{OH}$ . Bring back to the red color by dropwise addition of dilute  $\text{HCl}$ , and add 10 ml excess. Proceed with the molybdenum blue color development as described in Section 11.2.

11.1.4 If the expected arsenic content is in the range of 0.0002 to 0.0010 percent As, transfer either the entire initial distillate or the measured remaining distillate from Section 11.1.2 to a 250-ml beaker. Wash the cylinder with two successive portions of concentrated  $\text{HNO}_3$ , adding each portion to the distillate in the beaker. Add 4 ml of concentrated  $\text{HClO}_4$ , a boiling granule, and cover with a flat watch glass placed slightly to one side. Boil gently on a hot plate until the volume is reduced to approximately 10 ml. Add 3 ml of  $\text{HNO}_3$ , and continue the evaporation until  $\text{HClO}_4$  is refluxing on the beaker cover. Cool briefly, rinse the underside of the watch glass and the inside of the beaker with about 3-5 ml of water, cover, and continue the evaporation to expel all but 2 ml of the  $\text{HClO}_4$ .

NOTE: If the solution appears cloudy due to a small amount of antimony distilling over, add 4 ml of 50 percent  $\text{HCl}$  and 5 ml of water, cover, and warm gently until clear. If cloudiness persists, add 5 ml of  $\text{HNO}_3$  and 2 ml  $\text{H}_2\text{SO}_4$ . Continue the evaporation of volatile acids to solubilize the antimony until dense white fumes of  $\text{H}_2\text{SO}_4$  appear. Retain at least 1 ml of the  $\text{H}_2\text{SO}_4$ .

11.1.5 To the 2 ml of  $\text{HClO}_4$  solution or 1 ml of  $\text{H}_2\text{SO}_4$  solution, add 15 ml of water, boil gently for 2 minutes, and then cool. Proceed with the molybdenum blue color development by neutralizing the solution directly in the beaker just to the yellow indicator color by dropwise addition of  $\text{NH}_4\text{OH}$ . Obtain the red color by dropwise addition of dilute  $\text{HCl}$ . Transfer the solution to a 50-ml volumetric flask. Rinse the beaker successively with 10 ml of dilute  $\text{HCl}$ , followed by several small portions of water. At this point the volume of solution in the flask should be no more than 40 ml. Continue with the color development as described in Section 11.2.

## 11.2 Analysis.

11.2.1 Add 1 ml of  $\text{KBrO}_3$  solution to the flask and heat on a low-temperature hot plate to about  $50^\circ\text{C}$  ( $122^\circ\text{F}$ ) to oxidize the arsenic and methyl orange. Add 5.0 ml of ammonium molybdate solution to the warm solution and mix. Add 2.0 ml of hydrazine sulfate solution, dilute until the solution comes within the neck of the flask, and mix. Place the flask in a 400 ml beaker, 80 percent full of boiling water, for 10 minutes. Enough heat must be supplied to prevent the water bath from cooling much below the boiling point upon inserting the volumetric flask. Remove the flask, cool to room temperature, dilute to the mark, and mix.

11.2.2 Transfer a suitable portion of the reference solution to an absorption cell, and adjust the spectrophotometer to the initial setting using a light band centered at 660 nm. While maintaining this spectrophotometer adjustment, take the readings of the calibration solutions followed by the samples.

## 12.0 Data Analysis and Calculations

Same as in Method 108A, Section 12.0.

## 13.0 Method Performance. [Reserved]

## 14.0 Pollution Prevention. [Reserved]

## 15.0 Waste Management. [Reserved]

## 16.0 References

1. Ringwald, D. Arsenic Determination on Process Materials from ASARCO's Copper Smelter in Tacoma, Washington. Unpublished Report. Prepared for the Emission Measurement Branch, Technical Support Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. August 1980. 35 pp.

## 17.0 TABLES, DIAGRAMS, FLOWCHARTS, AND VALIDATION DATA

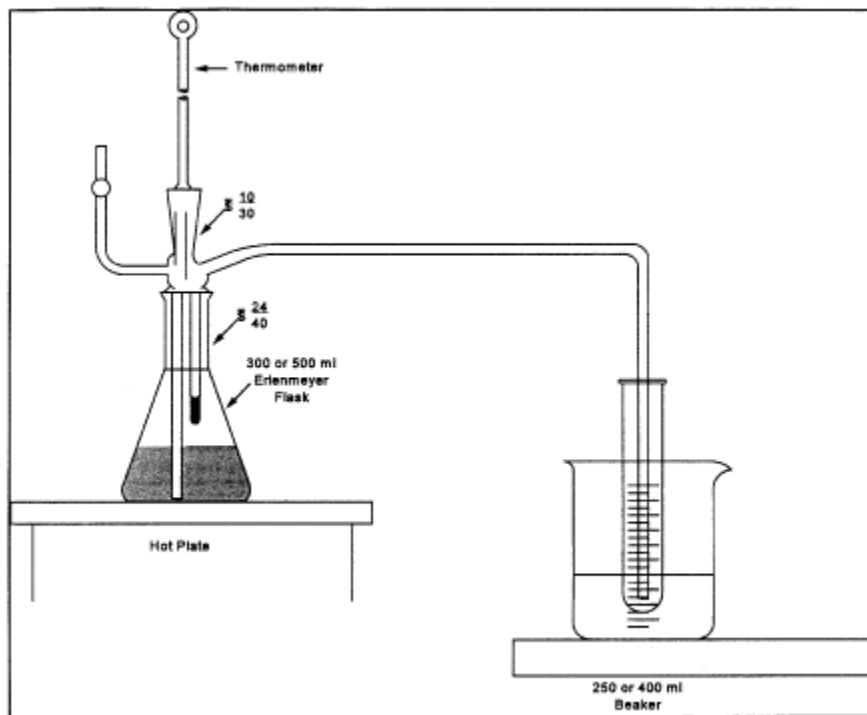


Figure 108C-1. Distillation Apparatus.

## METHOD 111—DETERMINATION OF POLONIUM-210 EMISSIONS FROM STATIONARY SOURCES

NOTE: This method does not include all of the specifications ( e.g., equipment and supplies) and procedures ( e.g., sampling and analytical) essential to its performance. Some material is incorporated by reference from methods in appendix A to 40 CFR part 60. Therefore, to obtain reliable results, persons

using this method should have a thorough knowledge of at least the following additional test methods: Method 1, Method 2, Method 3, and Method 5.

### 1.0 Scope and Application

#### 1.1 Analytes.

Analyte	CAS No.	Sensitivity
Polonium	7440-08-6	Not specified.

1.2 Applicability. This method is applicable for the determination of the polonium-210 content of particulate matter samples collected from stationary source exhaust stacks, and for the use of these data to calculate polonium-210 emissions from individual sources and from all affected sources at a facility.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

### 2.0 Summary of Method

A particulate matter sample, collected according to Method 5, is analyzed for polonium-210 content: the polonium-210 in the sample is put in solution, deposited on a metal disc, and the radioactive disintegration rate measured. Polonium in acid solution spontaneously deposits on surfaces of metals that are more electropositive than polonium. This principle is routinely used in the radiochemical analysis of polonium-210. Data reduction procedures are provided, allowing the calculation of polonium-210 emissions from individual sources and from all affected sources at a facility, using data obtained from Methods 2 and 5 and from the analytical procedures herein.

### 3.0 Definitions [Reserved]

### 4.0 Interferences [Reserved]

### 5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Corrosive Reagents. The following reagents are hazardous. Personal protective equipment and safe procedures are useful in preventing chemical splashes. If contact occurs, immediately flush with copious amounts of water at least 15 minutes. Remove clothing under shower and decontaminate. Treat residual chemical burns as thermal burns.

5.2.1 Hydrochloric Acid (HCl). Highly corrosive liquid with toxic vapors. Vapors are highly irritating to eyes, skin, nose, and lungs, causing severe damage. May cause bronchitis, pneumonia, or edema of lungs. Exposure to concentrations of 0.13 to 0.2 percent can be lethal to humans in a few minutes. Provide ventilation to limit exposure. Reacts with metals, producing hydrogen gas.

5.2.2 Hydrofluoric Acid (HF). Highly corrosive to eyes, skin, nose, throat, and lungs. Reaction to exposure may be delayed by 24 hours or more. Provide ventilation to limit exposure.

5.2.3 Nitric Acid ( $\text{HNO}_3$ ). Highly corrosive to eyes, skin, nose, and lungs. Vapors cause bronchitis, pneumonia, or edema of lungs. Reaction to inhalation may be delayed as long as 30 hours and still be fatal. Provide ventilation to limit exposure. Strong oxidizer. Hazardous reaction may occur with organic materials such as solvents.

5.2.4 Perchloric Acid ( $\text{HClO}_4$ ). Corrosive to eyes, skin, nose, and throat. Provide ventilation to limit exposure. Keep separate from water and oxidizable materials to prevent vigorous evolution of heat, spontaneous combustion, or explosion. Heat solutions containing  $\text{HClO}_4$  only in hoods specifically designed for  $\text{HClO}_4$ .

## 6.0 *Equipment and Supplies*

6.1 Alpha Spectrometry System. Consisting of a multichannel analyzer, biasing electronics, silicon surface barrier detector, vacuum pump and chamber.

6.2 Constant Temperature Bath at 85 °C (185 °F).

6.3 Polished Silver Discs. 3.8 cm diameter, 0.4 mm thick with a small hole near the edge.

6.4 Glass Beakers. 400 ml, 150 ml.

6.5 Hot Plate, Electric.

6.6 Fume Hood.

6.7 Teflon Beakers, 150 ml.

6.8 Magnetic Stirrer.

6.9 Stirring Bar.

6.10 Hooks. Plastic or glass, to suspend plating discs.

6.11 Internal Proportional Counter. For measuring alpha particles.

6.12 Nucleopore Filter Membranes. 25 mm diameter, 0.2 micrometer pore size or equivalent.

6.13 Planchets. Stainless steel, 32 mm diameter with 1.5 mm lip.

6.14 Transparent Plastic Tape. 2.5 cm wide with adhesive on both sides.

6.15 Epoxy Spray Enamel.

6.16 Suction Filter Apparatus. For 25 mm diameter filter.

6.17 Wash Bottles, 250 ml capacity.

6.18 Graduated Cylinder, plastic, 25 ml capacity.

6.19 Volumetric Flasks, 100 ml, 250 ml.

## 7.0 *Reagents and Standards*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

7.1 Ascorbic Acid.

7.2 Ammonium Hydroxide ( $\text{NH}_4\text{OH}$ ), 15 M.

7.3 Water. Deionized distilled, to conform to ASTM D 1193-77 or 91 (incorporated by reference—see § 61.18), Type 3. Use in all dilutions requiring water.

7.4 Ethanol ( $\text{C}_2\text{H}_5\text{OH}$ ), 95 percent.

7.5 Hydrochloric Acid, 12 M.

7.6 Hydrochloric Acid, 1 M. Dilute 83 ml of the 12 M HCl to 1 liter with distilled water.

7.7 Hydrofluoric Acid, 29 M.

7.8 Hydrofluoric Acid, 3 M. Dilute 52 ml of the 29 M HF to 500 ml with distilled water. Use a plastic graduated cylinder and storage bottle.

7.9 Lanthanum Carrier, 0.1 mg  $\text{La}^{+3}$ /ml. Dissolve 0.078 gram lanthanum nitrate,  $\text{La}(\text{NO}_3)_3 \cdot 6\text{H}_2\text{O}$  in 250 ml of 1 M HCl.

7.10 Nitric Acid, 16 M.

7.11 Perchloric Acid, 12 M.

7.12 Polonium-209 Solution.

7.13 Silver Cleaner. Any mild abrasive commercial silver cleaner.

7.14 Degreaser.

7.15 Standard Solution. Standardized solution of an alpha-emitting actinide element, such as plutonium-239 or americium-241.

## 8.0 *Sample Collection, Preservation, Transport, and Storage. [Reserved]*

## 9.0 *Quality Control*

9.1 General Requirement.

9.1.1 All analysts using this method are required to demonstrate their ability to use the method and to define their respective accuracy and precision criteria.



## 9.2 MISCELLANEOUS QUALITY CONTROL MEASURES

Section	Quality control measure	Effect
10.1	Standardization of alpha spectrometry system	Ensure precision of sample analyses.
10.3	Standardization of internal proportional counter	Ensure precise sizing of sample aliquot.
11.1, 11.2	Determination of procedure background and instrument background	Minimize background effects.

### 10.0 Calibration and Standardization

#### 10.1 Standardization of Alpha Spectrometry System.

10.1.1 Add a quantity of the actinide standard solution to a 100 ml volumetric flask so that the final concentration when diluted to a volume of 100 ml will be approximately 1<sub>p</sub> Ci/ml.

10.1.2 Add 10 ml of 16 M HNO<sub>3</sub> and dilute to 100 ml with water.

10.1.3 Add 20 ml of 1 M HCl to each of six 150 ml beakers. Add 1.0 ml of lanthanum carrier, 0.1 mg lanthanum per ml, to the acid solution in each beaker.

10.1.4 Add 1.0 ml of the 1 pCi/ml working solution (from Section 10.1.1) to each beaker. Add 5.0 ml of 3 M HF to each beaker.

10.1.5 Cover beakers and allow solutions to stand for a minimum of 30 minutes. Filter the contents of each beaker through a separate filter membrane using the suction filter apparatus. After each filtration, wash the filter membrane with 10 ml of distilled water and 5 ml of ethanol, and allow the filter membrane to air dry on the filter apparatus.

10.1.6 Carefully remove the filter membrane and mount it, filtration side up, with double-side tape on the inner surface of a planchet. Place planchet in an alpha spectrometry system and count each planchet for 1000 minutes.

10.1.7 Calculate the counting efficiency of the detector for each aliquot of the 1 pCi/ml actinide working solution using Eq. 111-1 in Section 12.2.

10.1.8 Determine the average counting efficiency of the detector,  $E_c$ , by calculating the average of the six determinations.

#### 10.2 Preparation of Standardized Solution of Polonium-209.

10.2.1 Add a quantity of the Po-209 solution to a 100 ml volumetric flask so that the final concentration when diluted to a 100 ml volume will be approximately 1 pCi/ml.

10.2.2 Follow the procedures outlined in Sections 10.1.2 through 10.1.6, except substitute 1.0 ml of polonium-209 tracer solution (Section 10.2.1) and 3.0 ml of 15 M ammonium hydroxide for the 1 pCi/ml actinide working solution and the 3 M HF, respectively.

10.2.3 Calculate the activity of each aliquot of the polonium-209 tracer solution using Eq. 111-2 in Section 12.3.

10.2.4 Determine the average activity of the polonium-209 tracer solution,  $F$ , by averaging the results of the six determinations.

### 10.3 Standardization of Internal Proportional Counter

10.3.1 Add a quantity of the actinide standard solution to a 100 ml volumetric flask so that the final concentration when diluted to a 100 ml volume will be approximately 100 pCi/ml.

10.3.2 Follow the procedures outlined in Sections 10.1.2 through 10.1.6, except substitute the 100 pCi/ml actinide working solution for the 1 pCi/ml solution, place the planchet in an internal proportional counter (instead of an alpha spectrometry system), and count for 100 minutes (instead of 1000 minutes).

10.3.3 Calculate the counting efficiency of the internal proportional counter for each aliquot of the 100 pCi/ml actinide working solution using Eq. 111-3 in 12.4.

10.3.4 Determine the average counting efficiency of the internal proportional counter,  $E_i$ , by averaging the results of the six determinations.

## 11.0 ANALYTICAL PROCEDURE

NOTE: Perform duplicate analyses of all samples, including background counts and Method 5 samples. Duplicate measurements are considered acceptable when the difference between them is less than two standard deviations as described in EPA 600/4-77-001 or subsequent revisions.

11.1 Determination of Procedure Background. Background counts used in all equations are determined by performing the specific analysis required using the analytical reagents only. All procedure background counts and sample counts for the internal proportional counter should utilize a counting time of 100 minutes; for the alpha spectrometry system, 1000 minutes. These background counts should be performed no less frequently than once per 10 sample analyses.

11.2 Determination of Instrument Background. Instrument backgrounds of the internal proportional counter and the alpha spectrometry system should be determined on a weekly basis. Instrument background should not exceed procedure background. If this occurs, it may be due to a malfunction or contamination, and should be corrected before use.

11.4 Sample Preparation. Treat the Method 5 samples [ *i.e.*, the glass fiber filter (Container No. 1) and the acetone rinse (Container No. 2)] as follows:

11.4.1 Container No. 1. Transfer the filter and any loose particulate matter from the sample container to a 150-ml Teflon beaker.

11.4.2 Container No. 2. Note the level of liquid in the container, and confirm on the analysis sheet whether leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Transfer the contents to a 400-ml glass beaker. Add polonium-209 tracer solution to the glass beaker in an amount approximately equal to the amount of polonium-210 expected in the total particulate sample. Record the activity of the tracer solution added. Add 16 M nitric acid to the beaker to digest and loosen the residue.

11.4.3 Transfer the contents of the glass beaker to the Teflon beaker containing the glass fiber filter. Rinse the glass beaker with 16 M  $\text{HNO}_3$ . If necessary, reduce the volume in the beaker by evaporation until all of the nitric acid  $\text{HNO}_3$  from the glass beaker has been transferred to the Teflon beaker.

11.4.4 Add 30 ml of 29 M HF to the Teflon beaker and evaporate to near dryness on a hot plate in a properly operating hood.

NOTE: Do not allow the residue to go to dryness and overheat; this will result in loss of polonium.

11.4.5 Repeat step 11.4.4 until the filter is dissolved.

11.4.6 Add 100 ml of 16 M HNO<sub>3</sub> to the residue in the Teflon beaker and evaporate to near dryness.

NOTE: Do not allow the residue to go to dryness.

11.4.7 Add 50 ml of 16 M HNO<sub>3</sub> and 10 ml of 12 M perchloric acid to the Teflon beaker and heat until dense fumes of perchloric acid are evolved.

11.4.8 Repeat steps 11.4.4 to 11.4.7 as necessary until sample is completely dissolved.

11.4.9 Add 10 ml of 12 M HCl to the Teflon beaker and evaporate to dryness. Repeat additions and evaporations several times.

11.4.10 Transfer the sample to a 250-ml volumetric flask and dilute to volume with 3 M HCl.

11.5 Sample Screening. To avoid contamination of the alpha spectrometry system, check each sample as follows:

11.5.1 Add 20 ml of 1 M HCl, 1 ml of the lanthanum carrier solution (0.1 mg La/ml), a 1 ml aliquot of the sample solution from Section 11.4.10, and 3 ml of 15 M ammonium hydroxide to a 250-ml beaker in the order listed. Allow this solution to stand for a minimum of 30 minutes.

11.5.2 Filter the solution through a filter membrane using the suction filter apparatus. Wash the filter membrane with 10 ml of water and 5 ml of ethanol, and allow the filter membrane to air dry on the filter apparatus.

11.5.3 Carefully remove the filter membrane and mount it, filtration side up, with double-side tape on the inner surface of a planchet. Place the planchet in an internal proportional counter, and count for 100 minutes.

11.5.4 Calculate the activity of the sample using Eq. 111-4 in Section 12.5.

11.5.5 Determine the aliquot volume of the sample solution from Section 11.4.10 to be analyzed for polonium-210, such that the aliquot contains an activity between 1 and 4 picocuries. Use Eq. 111-5 in Section 12.6.

11.6 Preparation of Silver Disc for Spontaneous Electrodeposition.

11.6.1 Clean both sides of the polished silver disc with silver cleaner and with degreaser.

11.6.2 Place disc on absorbent paper and spray one side with epoxy spray enamel. This should be carried out in a well-ventilated area, with the disc lying flat to keep paint on one side only. Allow paint to dry for 24 hours before using disc for deposition.

11.7 Sample Analysis.

11.7.1 Add the aliquot of sample solution from Section 11.4.10 to be analyzed for polonium-210, the volume of which was determined in Section 11.5.5, to a suitable 200-ml container to be placed in a constant temperature bath.

NOTE: Aliquot volume may require a larger container.

11.7.2 If necessary, bring the volume to 100 ml with 1 M HCl. If the aliquot volume exceeds 100 ml, use total aliquot.

11.7.3 Add 200 mg of ascorbic acid and heat solution to 85 °C (185 °F) in a constant temperature bath.

11.7.4 Suspend a silver disc in the heated solution using a glass or plastic rod with a hook inserted through the hole in the disc. The disc should be totally immersed in the solution, and the solution must be stirred constantly, at all times during the plating operation. Maintain the disc in solution for 3 hours.

11.7.5 Remove the silver disc, rinse with deionized distilled water, and allow to air dry at room temperature.

11.7.6 Place the disc, with deposition side (unpainted side) up, on a planchet and secure with double-side plastic tape. Place the planchet with disc in alpha spectrometry system and count for 1000 minutes.

## 12.0 Data Analysis and Calculations.

### 12.1 Nomenclature.

A = Picocuries of polonium-210 in the Method 5 sample (from Section 12.8).

$A_A$  = Picocuries of actinide added.

$A_L$  = Volume of sample aliquot used, in ml (specified in Section 11.5.1 as 1 ml).

$A_S$  = Aliquot to be analyzed, in ml.

$B_B$  = Procedure background counts measured in polonium-209 spectral region.

$B_T$  = Polonium-209 tracer counts in sample.

$C_T$  = Total counts in polonium-210 spectral region.

D = Decay correction for time "t" (in days) from sample collection to sample counting, given by:  $D = e^{-0.0051t}$

$E_C$  = Average counting efficiency of detector (from Section 10.1.8), as counts per disintegration.

$E_{Ci}$  = Counting efficiency of the detector for aliquot i of the actinide working solution, counts per disintegration.

$E_I$  = Average counting efficiency of the internal proportional counter, as determined in Section 10.3.4, counts per disintegration.

$E_{Ii}$  = Counting efficiency of the internal proportional counter for aliquot i of the 100 pCi/ml actinide working solution, counts per disintegration.

$E_Y$  = The fraction of polonium-209 recovered on the planchet (from Section 12.7).

$F$  = Average activity of polonium-209 in sample (from Section 10.2.4), in pCi.

$F_i$  = activity of aliquot  $i$  of the polonium-209 tracer solution, in pCi.

$L$  = Dilution factor (unitless). This is the volume of sample solution prepared (specified as 250 ml in Section 11.1.10) divided by the volume of the aliquot of sample solution analyzed for polonium-210 (from Section 11.7.1).

$M_i$  = Phosphorous rock processing rate of the source being tested, during run  $i$ , Mg/hr.

$M_k$  = Phosphate rock processed annually by source  $k$ , in Mg/yr.

$n$  = Number of calciners at the elemental phosphorus plant.

$P$  = Total activity of sample solution from Section 11.4.10, in pCi (see Eq. 111-4).

$Q_{sd}$  = Volumetric flow rate of effluent stream, as determined by Method 2, in dscm/hr.

$S$  = Annual polonium-210 emissions from the entire facility, in curies/yr.

$V_{m(std)}$  = Volume of air sample, as determined by Method 5, in dscm.

$X_k$  = Emission rate from source  $k$ , from Section 12.10, in curies/Mg.

$10^{-12}$  = Curies per picocurie.

2.22 = Disintegrations per minute per picocurie.

250 = Volume of solution from Section 11.4.10, in ml.

12.2 Counting Efficiency. Calculate the counting efficiency of the detector for each aliquot of the 1 pCi/ml actinide working solution using Eq. 111-1.

$$E_{\alpha} = \frac{C_s - C_B}{2.22 A_A T} \quad \text{Eq. 111-1}$$

Where:

$C_B$  = Background counts in same peak area as  $C_S$ .

$C_S$  = Gross counts in actinide peak.

$T$  = Counting time in minutes, specified in Section 10.1.6 as 1000 minutes.

12.3 Polonium-209 Tracer Solution Activity. Calculate the activity of each aliquot of the polonium-209 tracer solution using Eq. 111-2.

$$F_i = \frac{C_s - C_B}{2.22 E_{ci} T} \quad \text{Eq. 111-2}$$

Where:

$C_B$  = Background counts in the 4.88 MeV region of spectrum the in the counting time  $T$ .

$C_S$  = Gross counts of polonium-209 in the 4.88 MeV region of the spectrum in the counting time  $T$ .

T = Counting time, specified in Section 10.1.6 as 1000 minutes.

12.4 Control Efficiency of Internal Proportional Counter. Calculate the counting efficiency of the internal proportional counter for each aliquot of the 100 pCi/ml actinide working solution using Eq. 111-3.

$$E_R = \frac{C_S - C_B}{2.22 A_A T} \quad \text{Eq. 111-3}$$

Where:

C<sub>B</sub> = Gross counts of procedure background.

C<sub>S</sub> = Gross counts of standard.

T = Counting time in minutes, specified in Section 10.3.2 as 100 minutes.

12.5 Calculate the activity of the sample using Eq. 111-4.

$$P = \frac{250 (C_S - C_B)}{2.22 \bar{E}_I A_I T} \quad \text{Eq. 111-4}$$

Where:

C<sub>B</sub> = Total counts of procedure background. (See Section 11.1).

C<sub>S</sub> = Total counts of screening sample.

T = Counting time for sample and background (which must be equal), in minutes (specified in Section 11.5.3 as 100 minutes).

12.6 Aliquot Volume. Determine the aliquot volume of the sample solution from Section 11.4.10 to be analyzed for polonium-210, such that the aliquot contains an activity between 1 and 4 picocuries using Eq. 111-5.

$$A_s = \frac{250 (\text{desired picocuries in aliquot})}{P} \quad \text{Eq. 111-5}$$

12.7 Polonium-209 Recovery. Calculate the fraction of polonium-209 recovered on the planchet, E<sub>Y</sub>, using Eq. 111-6.

$$E_Y = \frac{B_T - B_B}{2.22 \bar{F} \bar{E}_C T} \quad \text{Eq. 111-6}$$

Where:

T = Counting time, specified in Section 11.1 as 1000 minutes.

12.8 Polonium-210 Activity. Calculate the activity of polonium-210 in the Method 5 sample (including glass fiber filter and acetone rinse) using Eq. 111-7.

$$A = \frac{(C_T - C_B) L}{2.22 E_y \overline{E_C} T D} \quad \text{Eq. 111-7}$$

Where:

$C_B$  = Procedure background counts in polonium-210 spectral region.

$T$  = Counting time, specified in Section 11.1 as 1000 minutes for all alpha spectrometry sample and background counts.

## 12.9 Emission Rate from Each Stack.

12.9.1 For each test run,  $i$ , on a stack, calculate the measured polonium-210 emission rate,  $R_{Si}$ , using Eq. 111-8.

$$R_{Si} = \frac{(10^{-12}) A Q_{sd}}{V_{m(Std)} M_i} \quad \text{Eq. 111-8}$$

12.9.2 Determine the average polonium-210 emission rate from the stack,  $R_S$ , by taking the sum of the measured emission rates for all runs, and dividing by the number of runs performed.

12.9.3 Repeat steps 12.9.1 and 12.9.2 for each stack of each calciner.

12.10 Emission Rate from Each Source. Determine the total polonium-210 emission rate,  $X_k$ , from each source,  $k$ , by taking the sum of the average emission rates from all stacks to which the source exhausts.

12.11 Annual Polonium-210 Emission Rate from Entire Facility. Determine the annual elemental phosphorus plant emissions of polonium-210,  $S$ , using Eq. 111-9.

$$S = \frac{\sum_{k=1}^n (X_k M_k)}{n} \quad \text{Eq. 111-9}$$

13.0 *Method Performance. [Reserved]*

14.0 *Pollution Prevention. [Reserved]*

15.0 *Waste Management. [Reserved]*

16.0 *References*

1. Blanchard, R.L. "Rapid Determination of Lead-210 and Polonium-210 in Environmental Samples by Deposition on Nickel." Anal. Chem., 38 :189, pp. 189-192. February 1966.

17.0 *Tables, Diagrams, Flowcharts, and Validation Data [Reserved]*

## METHOD 114—TEST METHODS FOR MEASURING RADIONUCLIDE EMISSIONS FROM STATIONARY SOURCES

### 1. Purpose and Background

This method provides the requirements for: (1) Stack monitoring and sample collection methods appropriate for radionuclides; (2) radiochemical methods which are used in determining the amounts of radionuclides collected by the stack sampling and; (3) quality assurance methods which are conducted in conjunction with these measurements. These methods are appropriate for emissions for stationary sources. A list of references is provided.

Many different types of facilities release radionuclides into air. These radionuclides differ in the chemical and physical forms, half-lives and type of radiation emitted. The appropriate combination of sample extraction, collection and analysis for an individual radionuclide is dependent upon many interrelated factors including the mixture of other radionuclides present. Because of this wide range of conditions, no single method for monitoring or sample collection and analysis of a radionuclide is applicable to all types of facilities. Therefore, a series of methods based on "principles of measurement" are described for monitoring and sample collection and analysis which are applicable to the measurement of radionuclides found in effluent streams at stationary sources. This approach provides the user with the flexibility to choose the most appropriate combination of monitoring and sample collection and analysis methods which are applicable to the effluent stream to be measured.

## *2. Stack Monitoring and Sample Collection Methods*

Monitoring and sample collection methods are described based on "principles of monitoring and sample collection" which are applicable to the measurement of radionuclides from effluent streams at stationary sources. Radionuclides of most elements will be in the particulate form in these effluent streams and can be readily collected using a suitable filter media. Radionuclides of hydrogen, oxygen, carbon, nitrogen, the noble gases and in some circumstances iodine will be in the gaseous form. Radionuclides of these elements will require either the use of an in-line or off-line monitor to directly measure the radionuclides, or suitable sorbers, condensers or bubblers to collect the radionuclides.

2.1 Radionuclides as Particulates. The extracted effluent stream is passed through a filter media to remove the particulates. The filter must have a high efficiency for removal of sub-micron particles. The guidance in ANSI/HPS N13.1-1999 (section 6.6.2 Filter media) shall be followed in using filter media to collect particulates (incorporated by reference—see § 61.18 of this part).

### *2.2 Radionuclides as Gases.*

2.2.1 The Radionuclide Tritium (H-3). Tritium in the form of water vapor is collected from the extracted effluent sample by sorption, condensation or dissolution techniques. Appropriate collectors may include silica gel, molecular sieves, and ethylene glycol or water bubblers.

Tritium in the gaseous form may be measured directly in the sample stream using Method B-1, collected as a gas sample or may be oxidized using a metal catalyst to tritiated water and collected as described above.

2.2.2 Radionuclides of Iodine. Iodine is collected from an extracted sample by sorption or dissolution techniques. Appropriate collectors may include charcoal, impregnated charcoal, metal zeolite and caustic solutions.

2.2.3 Radionuclides of Argon, Krypton and Xenon. Radionuclides of these elements are either measured directly by an in-line or off-line monitor, or are collected from the extracted sample by low temperature sorption techniques. Appropriate sorbers may include charcoal or metal zeolite.

2.2.4 Radionuclides of Oxygen, Carbon, Nitrogen and Radon. Radionuclides of these elements are measured directly using an in-line or off-line monitor. Radionuclides of carbon in the form of carbon dioxide may be collected by dissolution in caustic solutions.



## 2.3 Definition of Terms

*In-line monitor* means a continuous measurement system in which the detector is placed directly in or adjacent to the effluent stream. This may involve either gross radioactivity measurements or specific radionuclide measurements. Gross measurements shall be made in conformance with the conditions specified in Methods A-4, B-2 and G-4.

*Off-line monitor* means a measurement system in which the detector is used to continuously measure an extracted sample of the effluent stream. This may involve either gross radioactivity measurements or specific radionuclide measurements. Gross measurements shall be made in conformance with the conditions specified in Methods A-4, B-2 and G-4.

*Sample collection* means a procedure in which the radionuclides are removed from an extracted sample of the effluent using a collection media. These collection media include filters, absorbers, bubblers and condensers. The collected sample is analyzed using the methods described in Section 3.

## 3. Radionuclide Analysis Methods

A series of methods based on "principles of measurement" are described which are applicable to the analysis of radionuclides collected from airborne effluent streams at stationary sources. These methods are applicable only under the conditions stated and within the limitations described. Some methods specify that only a single radionuclide be present in the sample or the chemically separated sample. This condition should be interpreted to mean that no other radionuclides are present in quantities which would interfere with the measurement.

Also identified (Table 1) are methods for a selected list of radionuclides. The listed radionuclides are those which are most commonly used and which have the greatest potential for causing dose to members of the public. Use of methods based on principles of measurement other than those described in this section must be approved in advance of use by the Administrator. For radionuclides not listed in Table 1, any of the described methods may be used provided the user can demonstrate that the applicability conditions of the method have been met.

The type of method applicable to the analysis of a radionuclide is dependent upon the type of radiation emitted, i.e., alpha, beta or gamma. Therefore, the methods described below are grouped according to principles of measurements for the analysis of alpha, beta and gamma emitting radionuclides.

### 3.1 Methods for Alpha Emitting Radionuclides

#### 3.1.1 Method A-1, Radiochemistry-Alpha Spectrometry.

*Principle:* The element of interest is separated from other elements, and from the sample matrix using radiochemical techniques. The procedure may involve precipitation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet in a very thin film by electrodeposition or by coprecipitation on a very small amount of carrier, such as lanthanum fluoride. The deposited element is then counted with an alpha spectrometer. The activity of the nuclide of interest is measured by the number of alpha counts in the appropriate energy region. A correction for chemical yield and counting efficiency is made using a standardized radioactive nuclide (tracer) of the same element. If a radioactive tracer is not available for the element of interest, a predetermined chemical yield factor may be used.

*Applicability:* This method is applicable for determining the activity of any alpha-emitting radionuclide, regardless of what other radionuclides are present in the sample provided the chemical

separation step produces a very thin sample and removes all other radionuclides which could interfere in the spectral region of interest. APHA-605(2), ASTM-D-3972(13).

### 3.1.2 Method A-2, Radiochemistry-Alpha Counting.

*Principle:* The element of interest is separated from other elements, and from the sample matrix using radiochemistry. The procedure may involve precipitation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet in a thin film and counted with an alpha counter. A correction for chemical yield (if necessary) is made. The alpha count rate measures the total activity of all emitting radionuclides of the separated element.

*Applicability:* This method is applicable for the measurement of any alpha-emitting radionuclide, provided no other alpha emitting radionuclide is present in the separated sample. It may also be applicable for determining compliance, when other radionuclides of the separated element are present, provided that the calculated emission rate is assigned to the radionuclide which could be present in the sample that has the highest dose conversion factor. IDO-12096(18).

### 3.1.3 Method A-3, Direct Alpha Spectrometry.

*Principle:* The sample, collected on a suitable filter, is counted directly on an alpha spectrometer. The sample must be thin enough and collected on the surface of the filter so that any absorption of alpha particle energy in the sample or the filter, which would degrade the spectrum, is minimal.

*Applicability:* This method is applicable to simple mixtures of alpha emitting radionuclides and only when the amount of particulates collected on the filter paper are relatively small and the alpha spectra is adequately resolved. Resolutions should be 50 keV (FWHM) or better, ASTM-D-3084(16).

### 3.1.4 Method A-4, Direct Alpha Counting (Gross alpha determination).

*Principle:* The sample, collected on a suitable filter, is counted with an alpha counter. The sample must be thin enough so that self-absorption is not significant and the filter must be of such a nature that the particles are retained on the surface.

*Applicability:* Gross alpha determinations may be used to measure emissions of specific radionuclides only (1) when it is known that the sample contains only a single radionuclide, or the identity and isotopic ratio of the radionuclides in the sample are well-known, and (2) measurements using either Method A-1, A-2 or A-5 have shown that this method provides a reasonably accurate measurement of the emission rate. Gross alpha measurements are applicable to unidentified mixtures of radionuclides only for the purposes and under the conditions described in section 3.7. APHA-601(3), ASTM-D-1943(10).

### 3.1.5 Method A-5, Chemical Determination of Uranium.

*Principle:* Uranium may be measured chemically by either colorimetry or fluorometry. In both procedures, the sample is dissolved, the uranium is oxidized to the hexavalent form and extracted into a suitable solvent. Impurities are removed from the solvent layer. For colorimetry, dibenzoylmethane is added, and the uranium is measured by the absorbance in a colorimeter. For fluorometry, a portion of the solution is fused with a sodium fluoride-lithium fluoride flux and the uranium is determined by the ultraviolet activated fluorescence of the fused disk in a fluorometer.

*Applicability:* This method is applicable to the measurements of emission rates of uranium when the isotopic ratio of the uranium radionuclides is well known. ASTM-E-318(15), ASTM-D-2907(14).

### 3.1.6 Method A-6, Radon-222—Continuous Gas Monitor.

*Principle:* Radon-222 is measured directly in a continuously extracted sample stream by passing the air stream through a calibrated scintillation cell. Prior to the scintillation cell, the air stream is treated to remove particulates and excess moisture. The alpha particles from radon-222 and its decay products strike a zinc sulfide coating on the inside of the scintillation cell producing light pulses. The light pulses are detected by a photomultiplier tube which generates electrical pulses. These pulses are processed by the system electronics and the read out is in pCi/l of radon-222.

*Applicability:* This method is applicable to the measurement of radon-222 in effluent streams which do not contain significant quantities of radon-220. Users of this method should calibrate the monitor in a radon calibration chamber at least twice per year. The background of the monitor should also be checked periodically by operating the instrument in a low radon environment. EPA 520/1-89-009(24).

### 3.1.7 Method A-7, Radon-222-Alpha Track Detectors

*Principle:* Radon-222 is measured directly in the effluent stream using alpha track detectors (ATD). The alpha particles emitted by radon-222 and its decay products strike a small plastic strip and produce submicron damage tracks. The plastic strip is placed in a caustic solution that accentuates the damage tracks which are counted using a microscope or automatic counting system. The number of tracks per unit area is correlated to the radon concentration in air using a conversion factor derived from data generated in a radon calibration facility.

*Applicability:* Prior approval from EPA is required for use of this method. This method is only applicable to effluent streams which do not contain significant quantities of radon-220, unless special detectors are used to discriminate against radon-220. This method may be used only when ATDs have been demonstrated to produce data comparable to data obtained with Method A-6. Such data should be submitted to EPA when requesting approval for the use of this method. EPA 520/1-89-009(24).

## 3.2 Methods for Gaseous Beta Emitting Radionuclides.

### 3.2.1 Method B-1, Direct Counting in Flow-Through Ionization Chambers.

*Principle:* An ionization chamber containing a specific volume of gas which flows at a given flow rate through the chamber is used. The sample (effluent stream sample) acts as the counting gas for the chamber. The activity of the radionuclide is determined from the current measured in the ionization chamber.

*Applicability:* This method is applicable for measuring the activity of a gaseous beta-emitting radionuclide in an effluent stream that is suitable as a counting gas, when no other beta-emitting nuclides are present. DOE/EP-0096(17), NCRP-58(23).

### 3.2.2 Method B-2, Direct Counting With In-line or Off-line Beta Detectors.

*Principle:* The beta detector is placed directly in the effluent stream (in-line) or an extracted sample of the effluent stream is passed through a chamber containing a beta detector (off-line). The activities of the radionuclides present in the effluent stream are determined from the beta count rate, and a knowledge of the radionuclides present and the relationship of the gross beta count rate and the specific radionuclide concentration.

*Applicability:* This method is applicable only to radionuclides with maximum beta particle energies greater than 0.2 MeV. This method may be used to measure emissions of specific radionuclides only when it is known that the sample contains only a single radionuclide or the identity and isotopic ratio of

the radionuclides in the effluent stream are well known. Specific radionuclide analysis of periodic grab samples may be used to identify the types and quantities of radionuclides present and to establish the relationship between specific radionuclide analyses and gross beta count rates.

This method is applicable to unidentified mixtures of gaseous radionuclides only for the purposes and under the conditions described in section 3.7.

### 3.3 Methods for Non-Gaseous Beta Emitting Radionuclides.

#### 3.3.1 Method B-3, Radiochemistry-Beta Counting.

*Principle:* The element of interest is separated from other elements, and from the sample matrix by radiochemistry. This may involve precipitation, distillation, ion exchange, or solvent extraction. Carriers (elements chemically similar to the element of interest) may be used. The element is deposited on a planchet, and counted with a beta counter. Corrections for chemical yield, and decay (if necessary) are made. The beta count rate determines the total activity of all radionuclides of the separated element. This method may also involve the radiochemical separation and counting of a daughter element, after a suitable period of ingrowth, in which case it is specific for the parent nuclide.

*Applicability:* This method is applicable for measuring the activity of any beta-emitting radionuclide, with a maximum energy greater than 0.2 MeV, provided no other radionuclide is present in the separated sample. APHA-608(5).

#### 3.3.2 Method B-4, Direct Beta Counting (Gross beta determination).

*Principle:* The sample, collected on a suitable filter, is counted with a beta counter. The sample must be thin enough so that self-absorption corrections can be made.

*Applicability:* Gross beta measurements are applicable only to radionuclides with maximum beta particle energies greater than 0.2 MeV. Gross beta measurements may be used to measure emissions of specific radionuclides only (1) when it is known that the sample contains only a single radionuclide, and (2) measurements made using Method B-3 show reasonable agreement with the gross beta measurement. Gross beta measurements are applicable to mixtures of radionuclides only for the purposes and under the conditions described in section 3.7. APHA-602(4), ASTM-D-1890(11).

#### 3.3.3 Method B-5, Liquid Scintillation Spectrometry.

*Principle:* An aliquot of a collected sample or the result of some other chemical separation or processing technique is added to a liquid scintillation "cocktail" which is viewed by photomultiplier tubes in a liquid scintillation spectrometer. The spectrometer is adjusted to establish a channel or "window" for the pulse energy appropriate to the nuclide of interest. The activity of the nuclide of interest is measured by the counting rate in the appropriate energy channel. Corrections are made for chemical yield where separations are made.

*Applicability:* This method is applicable to any beta-emitting nuclide when no other radionuclide is present in the sample or the separated sample provided that it can be incorporated in the scintillation cocktail. This method is also applicable for samples which contain more than one radionuclide but only when the energies of the beta particles are sufficiently separated so that they can be resolved by the spectrometer. This method is most applicable to the measurement of low-energy beta emitters such as tritium and carbon-14. APHA-609(6), EML-LV-539-17(19).

### 3.4 Gamma Emitting Radionuclides

### 3.4.1 Method G-1, High Resolution Gamma Spectrometry.

*Principle:* The sample is counted with a high resolution gamma detector, usually either a Ge(Li) or a high purity Ge detector, connected to a multichannel analyzer or computer. The gamma emitting radionuclides in the sample are measured from the gamma count rates in the energy regions characteristic of the individual radionuclide. Corrections are made for counts contributed by other radionuclides to the spectral regions of the radionuclides of interest. Radiochemical separations may be made prior to counting but are usually not necessary.

*Applicability:* This method is applicable to the measurement of any gamma emitting radionuclide with gamma energies greater than 20 keV. It can be applied to complex mixtures of radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gases. The method may also be applied to the analysis of gaseous gamma emitting radionuclides directly in an effluent stream by passing the stream through a chamber or cell containing the detector. ASTM-3649(9), IDO-12096(18).

### 3.4.2 Method G-2, Low Resolution Gamma Spectrometry.

*Principle:* The sample is counted with a low resolution gamma detector, a thallium activated sodium iodide crystal. The detector is coupled to a photomultiplier tube and connected to a multichannel analyzer. The gamma emitting radionuclides in the sample are measured from the gamma count rates in the energy regions characteristic of the individual radionuclides. Corrections are made for counts contributed by other radionuclides to the spectral regions of the radionuclides of interest. Radiochemical separation may be used prior to counting to obtain less complex gamma spectra if needed.

*Applicability:* This method is applicable to the measurement of gamma emitting radionuclides with energies greater than 100 keV. It can be applied only to relatively simple mixtures of gamma emitting radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gas. The method can be applied to the analysis of gaseous radionuclides directly in an effluent stream by passing the gas stream through a chamber or cell containing the detector. ASTM-D-2459(12), EMSL-LV-0539-17(19).

### 3.4.3 Method G-3, Single Channel Gamma Spectrometry.

*Principle:* The sample is counted with a thallium activated sodium iodide crystal. The detector is coupled to a photomultiplier tube connected to a single channel analyzer. The activity of a gamma emitting radionuclide is determined from the gamma counts in the energy range for which the counter is set.

*Applicability:* This method is applicable to the measurement of a single gamma emitting radionuclide. It is not applicable to mixtures of radionuclides. The samples counted may be in the form of particulate filters, absorbers, liquids or gas. The method can be applied to the analysis of gaseous radionuclides directly in an effluent stream by passing the gas stream through a chamber or cell containing the detector.

### 3.4.4 Method G-4, Gross Gamma Counting.

*Principle:* The sample is counted with a gamma detector usually a thallium activated sodium iodine crystal. The detector is coupled to a photomultiplier tube and gamma rays above a specific threshold energy level are counted.

*Applicability:* Gross gamma measurements may be used to measure emissions of specific radionuclides only when it is known that the sample contains a single radionuclide or the identity and isotopic ratio of the radionuclides in the effluent stream are well known. When gross gamma

measurements are used to determine emissions of specific radionuclides periodic measurements using Methods G-1 or G-2 should be made to demonstrate that the gross gamma measurements provide reliable emission data. This method may be applied to analysis of gaseous radionuclides directly in an effluent stream by placing the detector directly in or adjacent to the effluent stream or passing an extracted sample of the effluent stream through a chamber or cell containing the detector.

3.5 Counting Methods. All of the above methods with the exception of Method A-5 involve counting the radiation emitted by the radionuclide. Counting methods applicable to the measurement of alpha, beta and gamma radiations are listed below. The equipment needed and the counting principles involved are described in detail in ASTM-3648(8).

#### 3.5.1 Alpha Counting:

- *Gas Flow Proportional Counters.* The alpha particles cause ionization in the counting gas and the resulting electrical pulses are counted. These counters may be windowless or have very thin windows.
- *Scintillation Counters.* The alpha particles transfer energy to a scintillator resulting in a production of light photons which strike a photomultiplier tube converting the light photons to electrical pulses which are counted. The counters may involve the use of solid scintillation materials such as zinc sulfide or liquid scintillation solutions.
- *Solid-State Counters.* Semiconductor materials, such as silicon surface-barrier p-n junctions, act as solid ionization chambers. The alpha particles interact with the detector producing electron hole pairs. The charged pair is collected by an applied electrical field and the resulting electrical pulses are counted.
- *Alpha Spectrometers.* Semiconductor detectors used in conjunction with multichannel analyzers for energy discrimination.

#### 3.5.2 Beta Counting:

- *Ionization Chambers.* These chambers contain the beta-emitting nuclide in gaseous form. The ionization current produced is measured.
- *Geiger-Muller (GM) Counters-or Gas Flow Proportional Counters.* The beta particles cause ionization in the counting gas and the resulting electrical pulses are counted. Proportional gas flow counters which are heavily shielded by lead or other metal, and provided with an anti-coincidence shield to reject cosmic rays, are called low background beta counters.
- *Scintillation Counters.* The beta particles transfer energy to a scintillator resulting in a production of light photons, which strike a photomultiplier tube converting the light photon to electrical pulses which are counted. This may involve the use of anthracene crystals, plastic scintillator, or liquid scintillation solutions with organic phosphors.
- *Liquid Scintillation Spectrometers.* Liquid scintillation counters which use two photomultiplier tubes in coincidence to reduce background counts. This counter may also electronically discriminate among pulses of a given range of energy.

#### 3.5.3 Gamma Counting:

- *Low-Resolution Gamma Spectrometers.* The gamma rays interact with thallium activated sodium iodide or cesium iodide crystal resulting in the release of light photons which strike a photomultiplier tube

converting the light pulses to electrical pulses proportional to the energy of the gamma ray. Multi-channel analyzers are used to separate and store the pulses according to the energy absorbed in the crystal.

- *High-Resolution gamma Spectrometers.* Gamma rays interact with a lithium-drifted (Ge(Li)) or high-purity germanium (HPGe) semiconductor detectors resulting in a production of electron-hole pairs. The charged pair is collected by an applied electrical field. A very stable low noise preamplifier amplifies the pulses of electrical charge resulting from the gamma photon interactions. Multichannel analyzers or computers are used to separate and store the pulses according to the energy absorbed in the crystal.

- *Single Channel Analyzers.* Thallium activated sodium iodide crystals used with a single window analyzer. Pulses from the photomultiplier tubes are separated in a single predetermined energy range.

3.5.4 Calibration of Counters. Counters are calibrated for specific radionuclide measurements using a standard of the radionuclide under either identical or very similar conditions as the sample to be counted. For gamma spectrometers a series of standards covering the energy range of interest may be used to construct a calibration curve relating gamma energy to counting efficiency.

In those cases where a standard is not available for a radionuclide, counters may be calibrated using a standard with energy characteristics as similar as possible to the radionuclide to be measured. For gross alpha and beta measurements of the unidentified mixtures of radionuclides, alpha counters are calibrated with a natural uranium standard and beta counters with a cesium-137 standard. The standard must contain the same weight and distribution of solids as the samples, and be mounted in an identical manner. If the samples contain variable amounts of solids, calibration curves relating weight of solids present to counting efficiency are prepared. Standards other than those prescribed may be used provided it can be shown that such standards are more applicable to the radionuclide mixture measured.

3.6 Radiochemical Methods for Selected Radionuclides. Methods for a selected list of radionuclides are listed in Table 1. The radionuclides listed are those which are most commonly used and which have the greatest potential for causing doses to members of the public. For radionuclides not listed in Table 1, methods based on any of the applicable "principles of measurement" described in section 3.1 through 3.4 may be used.

3.7 Applicability of Gross Alpha and Beta Measurements to Unidentified Mixtures of Radionuclides. Gross alpha and beta measurements may be used as a screening measurement as a part of an emission measurement program to identify the need to do specific radionuclide analyses or to confirm or verify that unexpected radionuclides are not being released in significant quantities.

Gross alpha (Method A-4) or gross beta (Methods B-2 or B-4) measurements may also be used for the purpose of comparing the measured concentrations in the effluent stream with the limiting "Concentration Levels for Environmental Compliance" in table 2 of appendix E. For unidentified mixtures, the measured concentration value shall be compared with the lowest environmental concentration limit for any radionuclide which is not known to be absent from the effluent stream.

**TABLE 1—LIST OF APPROVED METHODS FOR SPECIFIC RADIONUCLIDES**

Radionuclide	Approved methods of analysis
Am-241	A-1, A-2, A-3, A-4
Ar-41	B-1, B-2, G-1, G-2, G-3, G-4
Ba-140	G-1, G-2, G-3, G-4
Br-82	G-1, G-2, G-3, G-4

<b>Radionuclide</b>	<b>Approved methods of analysis</b>
C-11	B-1, B-2, G-1, G-2, G-3, G-4
C-14	B-5
Ca-45	B-3, B-4, B-5
Ce-144	G-1, G-2, G-3, G-4
Cm-244	A-1, A-2, A-3, A-4
Co-60	G-1, G-2, G-3, G-4
Cr-51	G-1, G-2, G-3, G-4
Cs-134	G-1, G-2, G-3, G-4
Cs-137	G-1, G-2, G-3, G-4
Fe-55	B-5, G-1
Fe-59	G-1, G-2, G-3, G-4
Ga-67	G-1, G-2, G-3, G-4
H-3 (H <sub>2</sub> O)	B-5
H-3 (gas)	B-1
I-123	G-1, G-2, G-3, G-4
I-125	G-1
I-131	G-1, G-2, G-3, G-4
In-113m	G-1, G-2, G-3, G-4
Ir-192	G-1, G-2, G-3, G-4
Kr-85	B-1, B-2, B-5, G-1, G-2, G-3, G-4
Kr-87	B-1, B-2, G-1, G-2, G-3, G-4
Kr-88	B-1, B-2, G-1, G-2, G-3, G-4
Mn-54	G-1, G-2, G-3, G-4
Mo-99	G-1, G-2, G-3, G-4
N-13	B-1, B-2, G-1, G-2, G-3, G-4
O-15	B-1, B-2, G-1, G-2, G-3, G-4
P-32	B-3, B-4, B-5
Pm-147	B-3, B-4, B-5
Po-210	A-1, A-2, A-3, A-4
Pu-238	A-1, A-2, A-3, A-4
Pu-239	A-1, A-2, A-3, A-4
Pu-240	A-1, A-2, A-3, A-4



Radionuclide	Approved methods of analysis
Ra-226	A-1, A-2, G-1, G-2
S-35	B-5
Se-75	G-1, G-2, G-3, G-4
Sr-90	B-3, B-4, B-5
Tc-99	B-3, B-4, B-5
Te-201	G-1, G-2, G-3, G-4
Uranium (total alpha)	A-1, A-2, A-3, A-4
Uranium (Isotopic)	A-1, A-3
Uranium (Natural)	A-5
Xe-133	G-1
Yb-169	G-1, G-2, G-3, G-4
Zn-65	G-1, G-2, G-3, G-4

#### 4. Quality Assurance Methods

Each facility required to measure their radionuclide emissions shall conduct a quality assurance program in conjunction with the radionuclide emission measurements. This program shall assure that the emission measurements are representative, and are of known precision and accuracy and shall include administrative controls to assure prompt response when emission measurements indicate unexpectedly large emissions. The program shall consist of a system of policies, organizational responsibilities, written procedures, data quality specifications, audits, corrective actions and reports. This quality assurance program shall include the following program elements:

4.1 The organizational structure, functional responsibilities, levels of authority and lines of communications for all activities related to the emissions measurement program shall be identified and documented.

4.2 Administrative controls shall be prescribed to ensure prompt response in the event that emission levels increase due to unplanned operations.

4.3 The sample collection and analysis procedures used in measuring the emissions shall be described including where applicable:

4.3.1 Identification of sampling sites and number of sampling points, including the rationale for site selections.

4.3.2 A description of sampling probes and representativeness of the samples.

4.3.3 A description of any continuous monitoring system used to measure emissions, including the sensitivity of the system, calibration procedures and frequency of calibration.

4.3.4 A description of the sample collection systems for each radionuclide measured, including frequency of collection, calibration procedures and frequency of calibration.

4.3.5 A description of the laboratory analysis procedures used for each radionuclide measured, including frequency of analysis, calibration procedures and frequency of calibration.

4.3.6 A description of the sample flow rate measurement systems or procedures, including calibration procedures and frequency of calibration.

4.3.7 A description of the effluent flow rate measurement procedures, including frequency of measurements, calibration procedures and frequency of calibration.

4.4 The objectives of the quality assurance program shall be documented and shall state the required precision, accuracy and completeness of the emission measurement data including a description of the procedures used to assess these parameters. Accuracy is the degree of agreement of a measurement with a true or known value. Precision is a measure of the agreement among individual measurements of the same parameters under similar conditions. Completeness is a measure of the amount of valid data obtained compared to the amount expected under normal conditions.

4.5 A quality control program shall be established to evaluate and track the quality of the emissions measurement data against preset criteria. The program should include where applicable a system of replicates, spiked samples, split samples, blanks and control charts. The number and frequency of such quality control checks shall be identified.

4.6 A sample tracking system shall be established to provide for positive identification of samples and data through all phases of the sample collection, analysis and reporting system. Sample handling and preservation procedures shall be established to maintain the integrity of samples during collection, storage and analysis.

4.7 Regular maintenance, calibration and field checks shall be performed for each sampling system in use by satisfying the requirements found in Table 2: Maintenance, Calibration and Field Check Requirements.

**TABLE 2—MAINTENANCE, CALIBRATION AND FIELD CHECK REQUIREMENTS**

<b>Sampling system components</b>	<b>Frequency of activity</b>
Cleaning of thermal anemometer elements	As required by application.
Inspect pitot tubes for contaminant deposits	At least annually.
Inspect pitot tube systems for leaks	At least annually.
Inspect sharp-edged nozzles for damage	At least annually or after maintenance that could cause damage.
Check nozzles for alignment, presence of deposits, or other potentially degrading factors	Annually.
Check transport lines of HEPA-filtered applications to determine if cleaning is required	Annually.
Clean transport lines	Visible deposits for HEPA-filtered applications. Mean mass of deposited material exceeds 1g/m <sup>2</sup> for other applications.
Inspect or test the sample transport system for leaks	At least annually.

Sampling system components	Frequency of activity
Check mass flow meters of sampling systems with a secondary or transfer standard	At least quarterly.
Inspect rotameters of sampling systems for presence of foreign matter	At the start of each sampling period.
Check response of stack flow rate systems	At least quarterly.
Calibration of flow meters of sampling systems	At least annually.
Calibration of effluent flow measurement devices	At least annually.
Calibration of timing devices	At least annually.

4.8 Periodic internal and external audits shall be performed to monitor compliance with the quality assurance program. These audits shall be performed in accordance with written procedures and conducted by personnel who do not have responsibility for performing any of the operations being audited.

4.9 A corrective action program shall be established including criteria for when corrective action is needed, what corrective actions will be taken and who is responsible for taking the corrective action.

4.10 Periodic reports to responsible management shall be prepared on the performance of the emissions measurements program. These reports should include assessment of the quality of the data, results of audits and description of corrective actions.

4.11 The quality assurance program should be documented in a quality assurance project plan that should address each of the above requirements.

## 5. References

(1) American National Standards Institute "Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities", ANSI-N13.1-1969, American National Standards Institute, New York, New York (1969).

(2) American Public Health Association, "Methods of Air Sampling", 2nd Edition, Method 605, "Tentative Method of Analysis for Plutonium Content of Atmospheric Particulate Matter". American Public Health Association, New York, NY (1977).

(3) Ibid, Method 601, "Tentative Method of Analysis for Gross Alpha Radioactivity Content of the Atmosphere".

(4) Ibid, Method 602, "Tentative Method of the Analysis for Gross Beta Radioactivity Content of the Atmosphere".

(5) Ibid, Method 608, "Tentative Method of Analysis for Strontium-90 Content of Atmospheric Particulate Matter".

(6) Ibid, Method 609, "Tentative Method of Analysis for Tritium Content of the Atmosphere".

- (7) Ibid, Method 603, "Tentative Method of Analysis for Iodine-131 Content of the Atmosphere".
- (8) American Society for Testing and Materials, 1986 Annual Book ASTM Standards, Designation D-3648-78, "Standard Practices for the Measurement of Radioactivity". American Society for Testing and Materials, Philadelphia, PA (1986).
- (9) Ibid, Designation D-3649-85, "Standard Practice for High Resolution Gamma Spectrometry".
- (10) Ibid, Designation D-1943-81, "Standard Test Method for Alpha Particle Radioactivity of Water".
- (11) Ibid, Designation D-1890-81, "Standard Test Method for Beta Particle Radioactivity of Water".
- (12) Ibid, Designation D-2459-72, "Standard Test Method for Gamma Spectrometry of Water".
- (13) Ibid, Designation D-3972-82, "Standard Test Method for Isotopic Uranium in Water by Radiochemistry".
- (14) Ibid, Designation D-2907-83, "Standard Test Methods for Microquantities of Uranium in Water by Fluorometry".
- (15) Ibid, Designation E-318, "Standard Test Method for Uranium in Aqueous Solutions by Colorimetry".
- (16) Ibid, Designation D-3084-75, "Standard Practice for Alpha Spectrometry of Water".
- (17) Corley, J.P. and C.D. Corbit, "A Guide for Effluent Radiological Measurements at DOE Installations", DOE/EP-0096, Pacific Northwest Laboratories, Richland, Washington (1983).
- (18) Department of Energy, "RESL Analytical Chemistry Branch Procedures Manual", IDO-12096, U.S. Department of Energy, Idaho Falls, Idaho (1982).
- (19) Environmental Protection Agency, "Radiochemical Analytical Procedures for Analysis of Environmental Samples", EMSL-LV-0539-17, U.S. Environmental Protection Agency, Environmental Monitoring and Support Laboratory, Las Vegas, Nevada (1979).
- (20) Environmental Protection Agency, "Radiochemistry Procedures Manual", EPA 520/5-84-006, Eastern Environmental Radiation Facility, Montgomery, Alabama (1984).
- (21) National Council on Radiation Protection and Measurements, NCRP Report No. 50, "Environmental Radiation Measurements", National Council on Radiation Protection and Measurement, Bethesda, Maryland (1976).
- (22) Ibid, Report No. 47, "Tritium Measurement Techniques". (1976).
- (23) Ibid, Report No. 58 "A Handbook of Radioactivity Measurement Procedures" (1985).
- (24) Environmental Protection Agency, "Indoor Radon and Radon Decay Product Measurement Protocols", EPA 520/1-89-009, U.S. Environmental Protection Agency, Washington, DC (1989).

This appendix describes the monitoring methods which must be used in determining the radon-222 emissions from underground uranium mines, uranium mill tailings piles, phosphogypsum stacks, and other piles of waste material emitting radon.

### 1. *Radon-222 Emissions from Underground Uranium Mine Vents*

1.1 Sampling Frequency and Calculation of Emissions. Radon-222 emissions from underground uranium mine vents shall be determined using one of the following methods:

1.1.1 Continuous Measurement. These measurements shall be made and the emissions calculated as follows:

(a) The radon-222 concentration shall be continuously measured at each mine vent whenever the mine ventilation system is operational.

(b) Each mine vent exhaust flow rate shall be measured at least 4 times per year.

(c) A weekly radon-222 emission rate for the mine shall be calculated and recorded weekly as follows:

$$A_w = C_1 Q_1 T_1 + C_2 Q_2 T_2 + \dots C_i Q_i T_i$$

Where:

$A_w$  = Total radon-222 emitted from the mine during week ( $C_i$ )

$C_i$  = Average radon-222 concentration in mine vent i ( $C_i/m^3$ )

$Q_i$  = Volumetric flow rate from mine vent i ( $m^3/hr$ )

$T_i$  = Hours of mine ventilation system operation during week for mine vent i (hr)

(d) The annual radon-222 emission rate is the sum of the weekly emission rates during a calendar year.

1.1.2 Periodic Measurement. This method is applicable only to mines that continuously operate their ventilation system except for extended shutdowns. Mines which start up and shut down their ventilation system frequently must use the continuous measurement method describe in Section 1.1.1 above. Emission rates determined using periodic measurements shall be measured and calculated as follows:

(a) The radon-222 shall be continuously measured at each mine vent for at least one week every three months.

(b) Each mine vent exhaust flow rate shall be measured at least once during each of the radon-222 measurement periods.

(c) A weekly radon-222 emission rate shall be calculated for each weekly period according to the method described in Section 1.1.1. In this calculation  $T=168$  hr.

(d) The annual radon-222 emission rate from the mine should be calculated as follows:

$$A_y = \frac{52 - W_s}{n} (A_{w1} + A_{w2} + \cdots A_{wi})$$

Where:

$A_y$  =Annual radon-222 emission rate from the mine(Ci)

$A_{wi}$  =Weekly radon-222 emission rate during the measurement period i (Ci)

n=Number of weekly measurement periods per year

$W_s$  =Number of weeks during the year that the mine ventilation system is shut down in excess of 7 consecutive days, i.e. the sum of the number of weeks each shut down exceeds 7 days

## 1.2 Test Methods and Procedures

Each underground mine required to test its emissions, unless an equivalent or alternative method has been approved by the Administrator, shall use the following test methods:

1.2.1 Test Method 1 of appendix A to part 60 shall be used to determine velocity traverses. The sampling point in the duct shall be either the centroid of the cross section or the point of average velocity.

1.2.2 Test Method 2 of appendix A to part 60 shall be used to determine velocity and volumetric flow rates.

1.2.3 Test Methods A-6 or A-7 of appendix B, Method 114 to part 61 shall be used for the analysis of radon-222. Use of Method A-7 requires prior approval of EPA based on conditions described in appendix B.

1.2.4 A quality assurance program shall be conducted in conformance with the programs described for Continuous Radon Monitors and Alpha Track Detectors in EPA 520/1-89-009. (2)

## 2. Radon-222 Emissions from Uranium Mill Tailings Piles

### 2.1 Measurement and Calculation of Radon Flux from Uranium Mill Tailings Piles.

2.1.1 Frequency of Flux Measurement. A single set of radon flux measurements may be made, or if the owner or operator chooses, more frequent measurements may be made over a one year period. These measurements may involve quarterly, monthly or weekly intervals. All radon measurements shall be made as described in paragraphs 2.1.2 through 2.1.6 except that for measurements made over a one year period, the requirement of paragraph 2.1.4(c) shall not apply. The mean radon flux from the pile shall be the arithmetic mean of the mean radon flux for each measurement period. The weather conditions, moisture content of the tailings and area of the pile covered by water existing at the time of the measurement shall be chosen so as to provide measurements representative of the long term radon flux from the pile and shall be subject to EPA review and approval.

2.1.2 Distribution of Flux Measurements. The distribution and number of radon flux measurements required on a pile will depend on clearly defined areas of the pile (called regions) that can have significantly different radon fluxes due to surface conditions. The mean radon flux shall be determined for each individual region of the pile. Regions that shall be considered for operating mill tailings piles are:

(a) Water covered areas,

- (b) Water saturated areas (beaches),
- (c) Dry top surface areas, and
- (d) Sides, except where earthen material is used in dam construction.

For mill tailings after disposal the pile shall be considered to consist of only one region.

2.1.3 Number of Flux Measurements. Radon flux measurements shall be made within each region on the pile, except for those areas covered with water. Measurements shall be made at regularly spaced locations across the surface of the region, realizing that surface roughness will prohibit measurements in some areas of a region. The minimum number of flux measurements considered necessary to determine a representative mean radon flux value for each type of region on an operating pile is:

- (a) Water covered area—no measurements required as radon flux is assumed to be zero,
- (b) Water saturated beaches—100 radon flux measurements,
- (c) Loose and dry top surface—100 radon flux measurements,
- (d) Sides—100 radon flux measurements, except where earthen material is used in dam construction.

For a mill tailings pile after disposal which consists of only one region a minimum of 100 measurements are required.

2.1.4 Restrictions to Radon Flux Measurements. The following restrictions are placed on making radon flux measurements:

- (a) Measurements shall not be initiated within 24 hours of a rainfall.
- (b) If a rainfall occurs during the 24 hour measurements period, the measurement is invalid if the seal around the lip of the collector has washed away or if the collector is surrounded by water.
- (c) Measurements shall not be performed if the ambient temperature is below 35 °F or if the ground is frozen.

2.1.5 Areas of Pile Regions. The approximate area of each region of the pile shall be determined in units of square meters.

2.1.6 Radon Flux Measurement. Measuring radon flux involves the adsorption of radon on activated charcoal in a large-area collector. The radon collector is placed on the surface of the pile area to be measured and allowed to collect radon for a time period of 24 hours. The radon collected on the charcoal is measured by gamma-ray spectroscopy. The detailed measurement procedure provided in appendix A of EPA 520/5-85-0029(1) shall be used to measure the radon flux on uranium mill tailings, except the surface of the tailings shall not be penetrated by the lip of the radon collector as directed in the procedure, rather the collector shall be carefully positioned on a flat surface with soil or tailings used to seal the edge.

2.1.7 Calculations. The mean radon flux for each region of the pile and for the total pile shall be calculated and reported as follows:

- (a) The individual radon flux calculations shall be made as provided in appendix A EPA 86 (1). The mean radon flux for each region of the pile shall be calculated by summing all individual flux

measurements for the region and dividing by the total number of flux measurements for the region.

(b) The mean radon flux for the total uranium mill tailings pile shall be calculated as follows.

$$J_s = \frac{J_1 A_1 + \cdots J_2 A_2 \cdots J_i A_i}{A_t}$$

Where:

$J_s$  = Mean flux for the total pile (pCi/m<sup>2</sup> -s)

$J_i$  = Mean flux measured in region i (pCi/m<sup>2</sup> -s)

$A_i$  = Area of region i (m<sup>2</sup> )

$A_t$  = Total area of the pile (m<sup>2</sup> )

2.1.8 Reporting. The results of individual flux measurements, the approximate locations on the pile, and the mean radon flux for each region and the mean radon flux for the total stack shall be included in the emission test report. Any condition or unusual event that occurred during the measurements that could significantly affect the results should be reported.

### 3.0 Radon-222 Emissions from Phosphogypsum Stacks.

3.1 Measurement and Calculation of the Mean Radon Flux. Radon flux measurements shall be made on phosphogypsum stacks as described below:

3.1.1 Frequency of Measurements. A single set of radon flux measurements may be made after the phosphogypsum stack becomes inactive, or if the owner or operator chooses, more frequent measurements may be made over a one year period. These measurements may involve quarterly, monthly or weekly intervals. All radon measurements shall be made as described in paragraphs 3.1.2 through 3.1.6 except that for measurements made over a one year period, the requirement of paragraph 3.1.4(c) shall not apply. For measurements made over a one year period, the radon flux shall be the arithmetic mean of the mean radon flux for each measurement period.

3.1.2 Distribution and Number of Flux Measurements. The distribution and number of radon flux measurements required on a stack will depend on clearly defined areas of the stack (called regions) that can have significantly different radon fluxes due to surface conditions. The mean radon flux shall be determined for each individual region of the stack. Regions that shall be considered are:

- (a) Water covered areas,
- (b) Water saturated areas (beaches),
- (c) Loose and dry top surface areas,
- (d) Hard-packed roadways, and
- (e) Sides.

3.1.3 Number of Flux Measurements. Radon flux measurements shall be made within each region on the phosphogypsum stack, except for those areas covered with water. Measurements shall be made at regularly spaced locations across the surface of the region, realizing that surface roughness will



prohibit measurements in some areas of a region. The minimum number of flux measurements considered necessary to determine a representative mean radon flux value for each type of region is:

- (a) Water covered area—no measurements required as radon flux is assumed to be zero,
- (b) Water saturated beaches—50 radon flux measurements,
- (c) Loose and dry top surface—100 radon flux measurements,
- (d) Hard-packed roadways—50 radon flux measurements, and
- (e) Sides—100 radon flux measurements.

A minimum of 300 measurements are required. A stack that has no water cover can be considered to consist of two regions, top and sides, and will require a minimum of only 200 measurements.

3.1.4 Restrictions to Radon Flux Measurements. The following restrictions are placed on making radon flux measurements:

- (a) Measurements shall not be initiated within 24 hours of a rainfall.
- (b) If a rainfall occurs during the 24 hour measurement period, the measurement is invalid if the seal around the lip of the collector has washed away or if the collector is surrounded by water.
- (c) Measurements shall not be performed if the ambient temperature is below 35 °F or if the ground is frozen.

3.1.5 Areas of Stack Regions. The approximate area of each region of the stack shall be determined in units of square meters.

3.1.6 Radon Flux Measurements. Measuring radon flux involves the adsorption of radon on activated charcoal in a large-area collector. The radon collector is placed on the surface of the stack area to be measured and allowed to collect radon for a time period of 24 hours. The radon collected on the charcoal is measured by gamma-ray spectroscopy. The detailed measurement procedure provided in appendix A of EPA 520/5-85-0029(1) shall be used to measure the radon flux on phosphogypsum stacks, except the surface of the phosphogypsum shall not be penetrated by the lip of the radon collector as directed in the procedure, rather the collector shall be carefully positioned on a flat surface with soil or phosphogypsum used to seal the edge.

3.1.7 Calculations. The mean radon flux for each region of the phosphogypsum stack and for the total stack shall be calculated and reported as follows:

- (a) The individual radon flux calculations shall be made as provided in appendix A EPA 86 (1). The mean radon flux for each region of the stack shall be calculated by summing all individual flux measurements for the region and dividing by the total number of flux measurements for the region.
- (b) The mean radon flux for the total phosphogypsum stack shall be calculated as follows.

$$J_s = \frac{J_1 A_1 + J_2 A_2 + \cdots J_i A_i}{A_t}$$

Where:

$J_s$  = Mean flux for the total stack (pCi/m<sup>2</sup> -s)

$J_i$  = Mean flux measured in region  $i$  ( $\text{pCi}/\text{m}^2 \cdot \text{s}$ )

$A_i$  = Area of region  $i$  ( $\text{m}^2$ )

$A_t$  = Total area of the stack

3.1.8 Reporting. The results of individual flux measurements, the approximate locations on the stack, and the mean radon flux for each region and the mean radon flux for the total stack shall be included in the emission test report. Any condition or unusual event that occurred during the measurements that could significantly affect the results should be reported.

#### 4.0 Quality Assurance Procedures for Measuring Rn-222 Flux

##### A. SAMPLING PROCEDURES

Records of field activities and laboratory measurements shall be maintained. The following information shall be recorded for each charcoal canister measurement:

- (a) Site
- (b) Name of pile
- (c) Sample location
- (d) Sample ID number
- (e) Date and time on
- (f) Date and time off
- (g) Observations of meteorological conditions and comments

Records shall include all applicable information associated with determining the sample measurement, calculations, observations, and comments.

##### B. SAMPLE CUSTODY

Custodial control of all charcoal samples exposed in the field shall be maintained in accordance with EPA chain-of-custody field procedures. A control record shall document all custody changes that occur between the field and laboratory personnel.

##### C. CALIBRATION PROCEDURES AND FREQUENCY

The radioactivity of two standard charcoal sources, each containing a carefully determined quantity of radium-226 uniformly distributed through 180g of activated charcoal, shall be measured. An efficiency factor is computed by dividing the average measured radioactivity of the two standard charcoal sources, minus the background, in cpm by the known radioactivity of the charcoal sources in dpm. The same two standard charcoal sources shall be counted at the beginning and at the end of each day's counting as a check of the radioactivity counting equipment. A background count using unexposed charcoal should also be made at the beginning and at the end of each counting day to check for inadvertent contamination of the detector or other changes affecting the background. The unexposed charcoal comprising the blank is changed with each new batch of charcoal used.

#### D. INTERNAL QUALITY CONTROL CHECKS AND FREQUENCY

The charcoal from every tenth exposed canister shall be recounted. Five percent of the samples analyzed shall be either blanks (charcoal having no radioactivity added) or samples spiked with known quantities of radium-226.

#### E. DATA PRECISION, ACCURACY, AND COMPLETENESS

The precision, accuracy, and completeness of measurements and analyses shall be within the following limits for samples measuring greater than  $1.0 \text{ pCi/m}^2 \text{ -s}$ .

(a) Precision: 10%

(b) Accuracy:  $\pm 10\%$

(c) Completeness: at least 85% of the measurements must yield useable results.

#### 5.0 REFERENCES

(1) Hartley, J.N. and Freeman, H.D., "Radon Flux Measurements on Gardinier and Royster phosphogypsum Piles Near Tampa and Mulberry, Florida," U.S. Environmental Protection Agency Report, EPA 520/5-85-029, January 1986.

(2) Environmental Protection Agency, "Indoor Radon and Radon Decay Product Measurement Protocols", EPA 520/1-89-009, U.S. Environmental Protection Agency, Washington, DC. (1989).

[38 FR 8826, Apr. 6, 1973]

EDITORIAL NOTES: 1. For FEDERAL REGISTER citations to appendix B see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at [www.fdsys.gov](http://www.fdsys.gov).

2. At 65 FR 62161, Oct. 17, 2000, appendix B to part 61 was amended by revising Methods 101, 101A, 102, 103, 104, 105, 106, 107, 107A, 108, 108A, 108B, 108C, and 111. However, because the amendment contains no revised text for Method 107A, this part of the revision could not be incorporated.

#### **Appendix C to Part 61—Quality Assurance Procedures**

##### *Procedure 1—Determination of Adequate Chromatographic Peak Resolution*

In this method of dealing with resolution, the extent to which one chromatographic peak overlaps another is determined.

For convenience, consider the range of the elution curve of each compound as running from  $-2\sigma$  to  $+2\sigma$ . This range is used in other resolution criteria, and it contains 95.45 percent of the area of a normal curve. If two peaks are separated by a known distance,  $b$ , one can determine the fraction of the area of one curve that lies within the range of the other. The extent to which the elution curve of a contaminant compound overlaps the curve of a compound that is under analysis is found by integrating the contaminant curve over the limits  $b-2\sigma_s$  to  $b+2\sigma_s$ , where  $\sigma_s$  is the standard deviation of the sample curve.

This calculation can be simplified in several ways. Overlap can be determined for curves of unit area; then actual areas can be introduced. Desired integration can be resolved into two integrals of the normal distribution function for which there are convenient calculation programs and tables. An example

would be Program 15 in Texas Instruments Program Manual ST1, 1975, Texas Instruments, Inc., Dallas, Texas 75222.

$$\frac{1}{\sqrt{2\pi}\sigma_s} \int_{b-2\sigma_s}^{b+2\sigma_s} e^{\left(\frac{-x^2}{2\sigma_s^2}\right)} dx = \frac{1}{\sqrt{2\pi}} \int_{\frac{b-2\sigma_s}{\sigma_c}}^{\frac{b+2\sigma_s}{\sigma_c}} e^{\left(\frac{-x^2}{2}\right)} dx = \frac{1}{\sqrt{2\pi}} \int_{\frac{b-2\sigma_s}{\sigma_c}}^{\infty} e^{\left(\frac{-x^2}{2}\right)} dx - \frac{1}{\sqrt{2\pi}} \int_{\frac{b+2\sigma_s}{\sigma_c}}^{\infty} e^{\left(\frac{-x^2}{2}\right)} dx$$

The following calculation steps are required:\*

$$1. \quad 2\sigma_s = t_s / \sqrt{2 \ln 2}$$

$$2. \quad \sigma_c = t_c / \sqrt{2 \ln 2}$$

$$3. \quad x_1 = (b - 2\sigma_s) / \sigma_c$$

$$4. \quad x_2 = (b + 2\sigma_s) / \sigma_c$$

$$5. \quad Q(x_1) = \frac{1}{\sqrt{2\pi}} \int_{x_1}^{\infty} e^{\left(\frac{-x^2}{2}\right)} dx$$

$$6. \quad Q(x_2) = \frac{1}{\sqrt{2\pi}} \int_{x_2}^{\infty} e^{\left(\frac{-x^2}{2}\right)} dx$$

$$7. \quad I_o = Q(x_1) - Q(x_2)$$

$$8. \quad A_o = I_o A_s / A_c$$

$$9. \quad \text{Percentage overlap} = A_o \times 100$$

where:

$A_s$  = Area of the sample peak of interest determined by electronic integration or by the formula  $A_s = t_s t_{hs}$ .

$A_c$  = Area of the contaminant peak, determined in the same manner as  $A_s$ .

$b$  = Distance on the chromatographic chart that separates the maxima of the two peaks.

$h_s$  = Peak height of the sample compound of interest, measured from the average value of the baseline to the maximum of the curve.

$t_s$  = Width of sample peak of interest at 1/2 peak height.

$t_c$  = Width of the contaminant peak at 1/2 of peak height.

$\sigma_s$  = Standard deviation of the sample compound of interest elution curve.

$\sigma_c$  = Standard deviation of the contaminant elution curve.

$Q(x_1)$  = Integral of the normal distribution function from  $x_1$  to infinity.

$Q(x_2)$  = Integral of the normal distribution function from  $x_2$  to infinity.

$I_o$  = Overlap integral.

$A_o$  = Area overlap fraction.

\*In most instances,  $Q(x_2)$  is very small and may be neglected.

In judging the suitability of alternate GC columns or the effects of altering chromatographic conditions, one can employ the area overlap as the resolution parameter with a specific maximum permissible value.

The use of Gaussian functions to describe chromatographic elution curves is widespread. However, some elution curves are highly asymmetric. In cases where the sample peak is followed by a contaminant that has a leading edge that rises sharply but the curve then tails off, it may be possible to define an effective width for  $t_c$  as "twice the distance from the leading edge to a perpendicular line through the maxim of the contaminant curve, measured along a perpendicular bisection of that line."

*Procedure 2—Procedure for Field Auditing GC Analysis*

Responsibilities of audit supervisor and analyst at the source sampling site include the following:

A. The audit supervisor verifies that audit cylinders are stored in a safe location both before and after the audit to prevent vandalism.

B. At the beginning and conclusion of the audit, the analyst records each cylinder number and pressure. An audit cylinder is never analyzed when the pressure drops below 200 psi.

C. During the audit, the analyst performs a minimum of two consecutive analyses of each audit cylinder gas. The audit must be conducted to coincide with the analysis of source test samples, normally immediately after GC calibration and prior to sample analyses.

D. At the end of audit analyses, the audit supervisor requests the calculated concentrations from the analyst and compares the results with the actual audit concentrations. If each measured concentration agrees with the respective actual concentration within  $\pm 10$  percent, he directs the analyst to begin analyzing source samples. Audit supervisor judgment and/or supervisory policy determine action when agreement is not within  $\pm 10$  percent. When a consistent bias in excess of 10 percent is found, it may be possible to proceed with the sample analysis, with a corrective factor to be applied to the results at a later time. However, every attempt should be made to locate the cause of the discrepancy, as it may be misleading. The audit supervisor records each cylinder number, cylinder pressure (at the end of the audit), and all calculated concentrations. The individual being audited must not under any circumstance be told actual audit concentrations until calculated concentrations have been submitted to the audit supervisor.

FIELD AUDIT REPORT

*Part A*— To be filled out by organization supplying audit cylinders.

1. Organization supplying audit sample(s) and shipping address

2. Audit supervisor, organization, and phone number

3. Shipping instructions: Name, Address, Attention

4. Guaranteed arrival date for cylinders

5. Planned shipping date for cylinders

6. Details on audit cylinders from last analysis

	Low conc.	High conc.
a. Date of last analysis		
b. Cylinder number		
c. Cylinder pressure, psi		
d. Audit gas(es)/balance gas		
e. Audit gas(es), ppm		
f. Cylinder construction		

*Part B*—To be filled out by audit supervisor.

1. Process sampled
2. Audit location
3. Name of individual audit
4. Audit date

5. Audit results:

	Low conc. cylinder	High conc. cylinder
a. Cylinder number		
b. Cylinder pressure before audit, psi		
c. Cylinder pressure after audit, psi		
d. Measured concentration, ppm Injection #1* Injection #2* Average		
e. Actual audit concentration, ppm (Part A, 6e)		
f. Audit accuracy: <sup>1</sup>		
Low Conc. Cylinder		
High Conc. Cylinder		
Percent <sup>1</sup> accuracy=		
Measured Conc.—Actual Conc.		
_____ ×100		
Actual Conc.		
g. Problems detected (if any)		

<sup>1</sup> Results of two consecutive injections that meet the sample analysis criteria of the test method.

## Appendix D to Part 61—Methods for Estimating Radionuclide Emissions

### 1. Purpose and Background

Facility owners or operators may estimate radionuclide emissions to the atmosphere for dose calculations instead of measuring emissions. Particulate emissions from mill tailings piles should be estimated using the procedures listed in reference re #2. All other emissions may be estimated by using the "Procedures" listed below, or using the method described in reference #1.

### 2. Procedure

To estimate emissions to the atmosphere:

(a) Determine the amount (in curies) used at facilities for the period under consideration. Radioactive materials in sealed packages that remain unopened, and have not leaked during the assessment period should not be included in the calculation.

(b) Multiply the amount used by the following factors which depend on the physical state of the radionuclide. They are:

- (i) 1 for gases;
- (ii)  $10^{-3}$  for liquids or particulate solids; and
- (iii)  $10^{-6}$  for solids.

If any nuclide is heated to a temperature of 100 degrees Celsius or more, boils at a temperature of 100 degrees Celsius or less, or is intentionally dispersed into the environment, it must be considered to be a gas.

(c) If a control device is installed between the place of use and the point of release, multiply emissions from (b) by an adjustment factor. These are presented in Table 1.

**TABLE 1—ADJUSTMENT TO EMISSION FACTORS FOR EFFLUENT CONTROLS**

Controls	Types of radionuclides controlled	Adjustment factor to emissions	Comments and conditions
HEPA filters	Particulates	0.01	Not applicable to gaseous radionuclides; periodic testing is prudent to ensure high removal efficiency.
Fabric filter	Particulates	0.1	Monitoring would be prudent to guard against tears in filter.
Sintered metal	Particulates	1	Insufficient data to make recommendation.
Activated carbon filters	Iodine gas	0.1	Efficiency is time dependent; monitoring is necessary to ensure effectiveness.
Douglas bags: Held one week or longer for decay	Xenon	0.5/wk	Based on xenon half-life of 5.3 days;

<b>Controls</b>	<b>Types of radionuclides controlled</b>	<b>Adjustment factor to emissions</b>	<b>Comments and conditions</b>
Douglas bags: Released within one week	Xenon	1	Provides no reduction of exposure to general public.
Venturi scrubbers	Particulates Gases	0.05 1	Although venturis may remove gases, variability in gaseous removal efficiency dictates adjustment factor for particulates only.
Packed bed scrubbers	Gases	0.1	Not applicable to particulates.
Electrostatic precipitators	Particulates	0.05	Not applicable for gaseous radionuclides
Xenon traps	Xenon	0.1	Efficiency is time dependent; monitoring is necessary to ensure effectiveness.
Fume hoods	All	1	Provides no reduction to general public exposures.
Vent stacks	All	1	Generally provides no reduction of exposure to general public.

#### *References*

(1) Environmental Protection Agency, "A Guide for Determining Compliance with the Clean Air Act Standards for Radionuclides Emissions from NRC-Licensed and Non-DOE Federal Facilities", EPA 520/1-89-002, January 1989.

(2) Nuclear Regulatory Commission, "Methods for Estimating Radioactive and Toxic Airborne Source Terms for Uranium Milling Operations", U.S. Nuclear Regulatory Commission Regulatory Guide 3.59, March 1987.

[54 FR 51711, Dec. 15, 1989]

### **Appendix E to Part 61—Compliance Procedures Methods for Determining Compliance With Subpart I**

#### *1. Purpose and Background*

This Appendix provides simplified procedures to reduce the burden on Nuclear Regulatory Commission (NRC) licensees, and non-Department of Energy Federal facilities in determining compliance with 40 CFR part 61, subpart I. The procedures consist of a series of increasingly more stringent steps, depending on the facility's potential to exceed the standard.

First, a facility can be found in compliance if the quantity of radioactive material possessed during the year is less than that listed in a table of annual possession quantities. A facility will also be in compliance if the average annual radionuclide emission concentration is less than that listed in a table of air concentration levels. If the facility is not in compliance by these tables, it can establish compliance by estimating a dose using screening procedure developed by the National Council on Radiation Protection and Measurements with a radiological source term derived using EPA approved emission factors. These



procedures are described in a "Guide for Determining Compliance with the Clean Air Act Standards for Radionuclide Emissions From NRC-Licensed and Non-DOE Federal Facilities."

A user-friendly computer program called COMPLY has been developed to reduce the burden on the regulated community. The Agency has also prepared a "User's Guide for the COMPLY Code" to assist the regulated community in using the code, and in handling more complex situations such as multiple release points. The basis for these compliance procedures are provided in "Background Information Document: Procedures Approved for Demonstrating Compliance with 40 CFR Part 61, Subpart I". The compliance model is the highest level in the COMPLY computer code and provides for the most realistic assessment of dose by allowing the use of site-specific information.

## 2. Table of Annual Possession Quantity

(a) Table 1 may be used for determining if facilities are in compliance with the standard. The possession table can only be used if the following conditions are met:

- (i) No person lives within 10 meters of any release point; and
- (ii) No milk, meat, or vegetables are produced within 100 meters of any release point.

(b) Procedures described in Reference (1) shall be used to determine compliance or exemption from reporting by use of Table 2.

**TABLE 1—ANNUAL POSSESSION QUANTITIES FOR ENVIRONMENTAL COMPLIANCE**

[Annual Possession Quantities (Ci/yr)]

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Ac-225	9.6E-05	9.6E-02	9.6E+01
Ac-227	1.6E-07	1.6E-04	1.6E-01
Ac-228	3.4E-03	3.4E+00	3.4E+03
Ag-106	1.6E+00	1.6E+03	1.6E+06
Ag-106m	2.6E-03	2.6E+00	2.6E+03
Ag-108m	6.5E-06	6.5E-03	6.5E+00
Ag-110m	9.4E-05	9.4E-02	9.4E+01
Ag-111	6.7E-02	6.7E+01	6.7E+04
Al-26	4.0E-06	4.0E-03	4.0E+00
Am-241	2.3E-06	2.3E-03	2.3E+00
Am-242	1.8E-02	1.8E+01	1.8E+04
Am-242m	2.5E-06	2.5E-03	2.5E+00
Am-243	2.3E-06	2.3E-03	2.3E+00
Am-244	4.6E-02	4.6E+01	4.6E+04
Am-245	7.0E+00	7.0E+03	7.0E+06

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Am-246	9.8E-01	9.8E+02	9.8E+05
Ar-37	1.4E+06		
Ar-41	1.4E+00		
As-72	2.9E-02	2.9E+01	2.9E+04
As-73	6.0E-02	6.0E+01	6.0E+04
As-74	4.3E-03	4.3E+00	4.3E+03
As-76	8.8E-02	8.8E+01	8.8E+04
As-77	7.9E-01	7.9E+02	7.9E+05
At-211	1.0E-02	1.0E+01	1.0E+04
Au-193	4.2E-01	4.2E+02	4.2E+05
Au-194	3.5E-02	3.5E+01	3.5E+04
Au-195	3.3E-03	3.3E+00	3.3E+03
Au-198	4.6E-02	4.6E+01	4.6E+04
Au-199	1.5E-01	1.5E+02	1.5E+05
Ba-131	1.0E-02	1.0E+01	1.0E+04
Ba-133	4.9E-05	4.9E-02	4.9E+01
Ba-133m	9.3E-02	9.3E+01	9.3E+04
Ba-135m	5.8E-01	5.8E+02	5.8E+05
Ba-139	4.7E+00	4.7E+03	4.7E+06
Ba-140	2.1E-03	2.1E+00	2.1E+03
Ba-141	1.3E+00	1.3E+03	1.3E+06
Ba-142	1.1E+00	1.1E+03	1.1E+06
Be-7	2.3E-02	2.3E+01	2.3E+04
Be-10	3.0E-03	3.0E+00	3.0E+03
Bi-206	3.1E-03	3.1E+00	3.1E+03
Bi-207	8.4E-06	8.4E-03	8.4E+00
Bi-210	4.2E-03	4.2E+00	4.2E+03
Bi-212	4.7E-02	4.7E+01	4.7E+04
Bi-213	6.0E-02	6.0E+01	6.0E+04
Bi-214	1.4E-01	1.4E+02	1.4E+05
Bk-249	7.0E-04	7.0E-01	7.0E+02
Bk-250	1.0E-01	1.0E+02	1.0E+05

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Br-77	7.5E-02	7.5E+01	7.5E+04
Br-80	1.2E+01	1.2E+04	1.2E+07
Br-80m	1.5E+00	1.5E+03	1.5E+06
Br-82	1.6E-02	1.6E+01	1.6E+04
Br-83	9.9E+00	9.9E+03	9.9E+06
Br-84	5.6E-01	5.6E+02	5.6E+05
C-11	1.3E+00	1.3E+03	1.3E+06
C-14	2.9E-01	2.9E+02	2.9E+05
Ca-41	2.7E-02	2.7E+01	2.7E+04
Ca-45	5.8E-02	5.8E+01	5.8E+04
Ca-47	1.1E-02	1.1E+01	1.1E+04
Cd-109	5.0E-03	5.0E+00	5.0E+03
Cd-113	3.3E-04	3.3E-01	3.3E+02
Cd-113m	4.4E-04	4.4E-01	4.4E+02
Cd-115	5.4E-02	5.4E+01	5.4E+04
Cd-115m	1.0E-02	1.0E+01	1.0E+04
Cd-117	5.6E-02	5.6E+01	5.6E+04
Cd-117m	1.3E-01	1.3E+02	1.3E+05
Ce-139	2.6E-03	2.6E+00	2.6E+03
Ce-141	1.8E-02	1.8E+01	1.8E+04
Ce-143	1.0E-01	1.0E+02	1.0E+05
Ce-144	1.7E-03	1.7E+00	1.7E+03
Cf-248	2.0E-05	2.0E-02	2.0E+01
Cf-249	1.7E-06	1.7E-03	1.7E+00
Cf-250	4.0E-06	4.0E-03	4.0E+00
Cf-251	1.7E-06	1.7E-03	1.7E+00
Cf-252	6.4E-06	6.4E-03	6.4E+00
Cf-253	3.3E-04	3.3E-01	3.3E+02
Cf-254	3.6E-06	3.6E-03	3.6E+00
Cl-36	1.9E-04	1.9E-01	1.9E+02
Cl-38	6.5E-01	6.5E+02	6.5E+05
Cm-242	6.0E-05	6.0E-02	6.0E+01

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Cm-243	3.3E-06	3.3E-03	3.3E+00
Cm-244	4.2E-06	4.2E-03	4.2E+00
Cm-245	2.3E-06	2.3E-03	2.3E+00
Cm-246	2.3E-06	2.3E-03	2.3E+00
Cm-247	2.3E-06	2.3E-03	2.3E+00
Cm-248	6.4E-07	6.4E-04	6.4E-01
Cm-249	4.6E+00	4.6E+03	4.6E+06
Cm-250	1.1E-07	1.1E-04	1.1E-01
Co-56	2.4E-04	2.4E-01	2.4E+02
Co-57	1.6E-03	1.6E+00	1.6E+03
Co-58	9.0E-04	9.0E-01	9.0E+02
Co-58m	1.7E-01	1.7E+02	1.7E+05
Co-60	1.6E-05	1.6E-02	1.6E+01
Co-60m	4.0E+00	4.0E+03	4.0E+06
Co-61	3.8E+00	3.8E+03	3.8E+06
Cr-49	9.0E-01	9.0E+02	9.0E+05
Cr-51	6.3E-02	6.3E+01	6.3E+04
Cs-129	1.5E-01	1.5E+02	1.5E+05
Cs-131	2.8E-01	2.8E+02	2.8E+05
Cs-132	1.3E-02	1.3E+01	1.3E+04
Cs-134	5.2E-05	5.2E-02	5.2E+01
Cs-134m	3.2E-01	3.2E+02	3.2E+05
Cs-135	2.4E-02	2.4E+01	2.4E+04
Cs-136	2.1E-03	2.1E+00	2.1E+03
Cs-137	2.3E-05	2.3E-02	2.3E+01
Cs-138	4.4E-01	4.4E+02	4.4E+05
Cu-61	4.0E-01	4.0E+02	4.0E+05
Cu-64	5.2E-01	5.2E+02	5.2E+05
Cu-67	1.5E-01	1.5E+02	1.5E+05
Dy-157	4.4E-01	4.4E+02	4.4E+05
Dy-165	5.6E+00	5.6E+03	5.6E+06
Dy-166	8.1E-02	8.1E+01	8.1E+04

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Er-169	4.0E-01	4.0E+02	4.0E+05
Er-171	3.6E-01	3.6E+02	3.6E+05
Es-253	2.6E-04	2.6E-01	2.6E+02
Es-254	2.3E-05	2.3E-02	2.3E+01
Es-254m	1.8E-03	1.8E+00	1.8E+03
Eu-152	1.6E-05	1.6E-02	1.6E+01
Eu-152m	3.5E-01	3.5E+02	3.5E+05
Eu-154	2.0E-05	2.0E-02	2.0E+01
Eu-155	5.2E-04	5.2E-01	5.2E+02
Eu-156	3.2E-03	3.2E+00	3.2E+03
F-18	5.6E-01	5.6E+02	5.6E+05
Fe-52	4.9E-02	4.9E+01	4.9E+04
Fe-55	1.4E-01	1.4E+02	1.4E+05
Fe-59	1.3E-03	1.3E+00	1.3E+03
Fm-254	1.8E-02	1.8E+01	1.8E+04
Fm-255	4.0E-03	4.0E+00	4.0E+03
Fr-223	1.4E-01	1.4E+02	1.4E+05
Ga-66	5.6E-02	5.6E+01	5.6E+04
Ga-67	1.1E-01	1.1E+02	1.1E+05
Ga-68	7.6E-01	7.6E+02	7.6E+05
Ga-72	3.6E-02	3.6E+01	3.6E+04
Gd-152	4.4E-06	4.4E-03	4.4E+00
Gd-153	2.0E-03	2.0E+00	2.0E+03
Gd-159	6.8E-01	6.8E+02	6.8E+05
Ge-68	2.3E-04	2.3E-01	2.3E+02
Ge-71	2.6E+00	2.6E+03	2.6E+06
Ge-77	1.0E-01	1.0E+02	1.0E+05
H-3	1.5E+01	1.5E+04	1.5E+07
Hf-181	2.5E-03	2.5E+00	2.5E+03
Hg-193m	9.5E-02	9.5E+01	9.5E+04
Hg-197	2.4E-01	2.4E+02	2.4E+05
Hg-197m	2.5E-01	2.5E+02	2.5E+05

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Hg-203	5.2E-03	5.2E+00	5.2E+03
Ho-166	2.8E-01	2.8E+02	2.8E+05
Ho-166m	6.0E-06	6.0E-03	6.0E+00
I-123	4.9E-01	4.9E+02	4.9E+05
I-124	9.3E-03	9.3E+00	9.3E+03
I-125	6.2E-03	6.2E+00	6.2E+03
I-126	3.7E-03	3.7E+00	3.7E+03
I-128	9.3E+00	9.3E+03	9.3E+06
I-129	2.6E-04	2.6E-01	2.6E+02
I-130	4.6E-02	4.6E+01	4.6E+04
I-131	6.7E-03	6.7E+00	6.7E+03
I-132	2.0E-01	2.0E+02	2.0E+05
I-133	6.7E-02	6.7E+01	6.7E+04
I-134	3.2E-01	3.2E+02	3.2E+05
I-135	1.2E-01	1.2E+02	1.2E+05
In-111	4.9E-02	4.9E+01	4.9E+04
In-113m	2.1E+00	2.1E+03	2.1E+06
In-114m	4.9E-03	4.9E+00	4.9E+03
In-115	2.7E-04	2.7E-01	2.7E+02
In-115m	1.4E+00	1.4E+03	1.4E+06
In-116m	3.5E-01	3.5E+02	3.5E+05
In-117	1.3E+00	1.3E+03	1.3E+06
In-117m	7.6E-02	7.6E+01	7.6E+04
Ir-190	3.5E-03	3.5E+00	3.5E+03
Ir-192	9.7E-04	9.7E-01	9.7E+02
Ir-194	2.5E-01	2.5E+02	2.5E+05
Ir-194m	1.5E-04	1.5E-01	1.5E+02
K-40	6.8E-05	6.8E-02	6.8E+01
K-42	2.9E-01	2.9E+02	2.9E+05
K-43	6.0E-02	6.0E+01	6.0E+04
K-44	4.9E-01	4.9E+02	4.9E+05
Kr-79	7.0E+00		

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Kr-81	1.8E+02		
Kr-83m	2.0E+04		
Kr-85	8.4E+02		
Kr-85m	1.1E+01		
Kr-87	2.0E+00		
Kr-88	4.2E-01		
La-140	1.6E-02	1.6E+01	1.6E+04
La-141	1.1E+00	1.1E+03	1.1E+06
La-142	2.3E-01	2.3E+02	2.3E+05
Lu-177	1.4E-01	1.4E+02	1.4E+05
Lu-177m	3.5E-04	3.5E-01	3.5E+02
Mg-28	2.1E-02	2.1E+01	2.1E+04
Mn-52	3.5E-03	3.5E+00	3.5E+03
Mn-52m	5.2E-01	5.2E+02	5.2E+05
Mn-53	5.7E-02	5.7E+01	5.7E+04
Mn-54	2.5E-04	2.5E-01	2.5E+02
Mn-56	2.5E-01	2.5E+02	2.5E+05
Mo-93	1.5E-03	1.5E+00	1.5E+03
Mo-99**	5.7E-02	5.7E+01	5.7E+04
Mo-101	8.4E-01	8.4E+02	8.4E+05
Na-22	3.2E-05	3.2E-02	3.2E+01
Na-24	2.6E-02	2.6E+01	2.6E+04
Nb-90	2.5E-02	2.5E+01	2.5E+04
Nb-93m	1.2E-02	1.2E+01	1.2E+04
Nb-94	6.0E-06	6.0E-03	6.0E+00
Nb-95	2.3E-03	2.3E+00	2.3E+03
Nb-95m	2.0E-02	2.0E+01	2.0E+04
Nb-96	2.5E-02	2.5E+01	2.5E+04
Nb-97	1.0E+00	1.0E+03	1.0E+06
Nd-147	3.0E-02	3.0E+01	3.0E+04
Nd-149	1.1E+00	1.1E+03	1.1E+06
Ni-56	2.0E-03	2.0E+00	2.0E+03

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Ni-57	2.1E-02	2.1E+01	2.1E+04
Ni-59	2.2E-02	2.2E+01	2.2E+04
Ni-63	1.4E-01	1.4E+02	1.4E+05
Ni-65	7.0E-01	7.0E+02	7.0E+05
Np-235	3.0E-02	3.0E+01	3.0E+04
Np-237	1.8E-06	1.8E-03	1.8E+00
Np-238	1.9E-02	1.9E+01	1.9E+04
Np-239	1.0E-01	1.0E+02	1.0E+05
Np-240	6.5E-01	6.5E+02	6.5E+05
Np-240m	4.7E+00	4.7E+03	4.7E+06
Os-185	9.2E-04	9.2E-01	9.2E+02
Os-191m	9.0E-01	9.0E+02	9.0E+05
Os-191	3.8E-02	3.8E+01	3.8E+04
Os-193	2.9E-01	2.9E+02	2.9E+05
P-32	1.7E-02	1.7E+01	1.7E+04
P-33	1.2E-01	1.2E+02	1.2E+05
Pa-230	6.3E-04	6.3E-01	6.3E+02
Pa-231	8.3E-07	8.3E-04	8.3E-01
Pa-233	9.3E-03	9.3E+00	9.3E+03
Pa-234	9.3E-02	9.3E+01	9.3E+04
Pb-203	8.3E-02	8.3E+01	8.3E+04
Pb-205	1.2E-02	1.2E+01	1.2E+04
Pb-209	1.1E+01	1.1E+04	1.1E+07
Pb-210	5.5E-05	5.5E-02	5.5E+01
Pb-211	1.2E-01	1.2E+02	1.2E+05
Pb-212	6.0E-03	6.0E+00	6.0E+03
Pb-214	1.2E-01	1.2E+02	1.2E+05
Pd-103	2.1E-01	2.1E+02	2.1E+05
Pd-107	8.2E-02	8.2E+01	8.2E+04
Pd-109	9.4E-01	9.4E+02	9.4E+05
Pm-143	7.6E-04	7.6E-01	7.6E+02
Pm-144	1.1E-04	1.1E-01	1.1E+02



<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Pm-145	5.2E-04	5.2E-01	5.2E+02
Pm-146	4.4E-05	4.4E-02	4.4E+01
Pm-147	2.6E-02	2.6E+01	2.6E+04
Pm-148	1.7E-02	1.7E+01	1.7E+04
Pm-148m	7.6E-04	7.6E-01	7.6E+02
Pm-149	2.8E-01	2.8E+02	2.8E+05
Pm-151	1.2E-01	1.2E+02	1.2E+05
Po-210	9.3E-05	9.3E-02	9.3E+01
Pr-142	2.8E-01	2.8E+02	2.8E+05
Pr-143	1.0E-01	1.0E+02	1.0E+05
Pr-144	1.5E+01	1.5E+04	1.5E+07
Pt-191	6.4E-02	6.4E+01	6.4E+04
Pt-193	2.1E-02	2.1E+01	2.1E+04
Pt-193m	4.8E-01	4.8E+02	4.8E+05
Pt-195m	1.4E-01	1.4E+02	1.4E+05
Pt-197	1.1E+00	1.1E+03	1.1E+06
Pt-197m	3.6E+00	3.6E+03	3.6E+06
Pu-236	7.0E-06	7.0E-03	7.0E+00
Pu-237	2.3E-02	2.3E+01	2.3E+04
Pu-238	2.7E-06	2.7E-03	2.7E+00
Pu-239	2.5E-06	2.5E-03	2.5E+00
Pu-240	2.5E-06	2.5E-03	2.5E+00
Pu-241	1.3E-04	1.3E-01	1.3E+02
Pu-242	2.5E-06	2.5E-03	2.5E+00
Pu-243	3.8E+00	3.8E+03	3.8E+06
Pu-244	2.4E-06	2.4E-03	2.4E+00
Pu-245	2.1E-01	2.1E+02	2.1E+05
Pu-246	4.8E-03	4.8E+00	4.8E+03
Ra-223	1.3E-04	1.3E-01	1.3E+02
Ra-224	3.2E-04	3.2E-01	3.2E+02
Ra-225	1.3E-04	1.3E-01	1.3E+02
Ra-226	5.5E-06	5.5E-03	5.5E+00

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Ra-228	1.3E-05	1.3E-02	1.3E+01
Rb-81	4.2E-01	4.2E+02	4.2E+05
Rb-83	1.4E-03	1.4E+00	1.4E+03
Rb-84	2.0E-03	2.0E+00	2.0E+03
Rb-86	1.7E-02	1.7E+01	1.7E+04
Rb-87	1.0E-02	1.0E+01	1.0E+04
Rb-88	1.7E+00	1.7E+03	1.7E+06
Rb-89	6.4E-01	6.4E+02	6.4E+05
Re-184	1.8E-03	1.8E+00	1.8E+03
Re-184m	3.6E-04	3.6E-01	3.6E+02
Re-186	1.9E-01	1.9E+02	1.9E+05
Re-187	9.3E+00	9.3E+03	9.3E+06
Re-188	3.7E-01	3.7E+02	3.7E+05
Rh-103m	1.7E+02	1.7E+05	1.7E+08
Rh-105	3.4E-01	3.4E+02	3.4E+05
Ru-97	8.3E-02	8.3E+01	8.3E+04
Ru-103	3.1E-03	3.1E+00	3.1E+03
Ru-105	2.9E-01	2.9E+02	2.9E+05
Ru-106	5.9E-04	5.9E-01	5.9E+02
S-35	7.5E-02	7.5E+01	7.5E+04
Sb-117	2.0E+00	2.0E+03	2.0E+06
Sb-122	3.9E-02	3.9E+01	3.9E+04
Sb-124	6.0E-04	6.0E-01	6.0E+02
Sb-125	1.4E-04	1.4E-01	1.4E+02
Sb-126	1.8E-03	1.8E+00	1.8E+03
Sb-126m	7.6E-01	7.6E+02	7.6E+05
Sb-127	2.0E-02	2.0E+01	2.0E+04
Sb-129	1.8E-01	1.8E+02	1.8E+05
Sc-44	1.4E-01	1.4E+02	1.4E+05
Sc-46	4.0E-04	4.0E-01	4.0E+02
Sc-47	1.1E-01	1.1E+02	1.1E+05
Sc-48	1.1E-02	1.1E+01	1.1E+04

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Sc-49	1.0E+01	1.0E+04	1.0E+07
Se-73	1.6E-01	1.6E+02	1.6E+05
Se-75	1.1E-03	1.1E+00	1.1E+03
Se-79	6.9E-03	6.9E+00	6.9E+03
Si-31	4.7E+00	4.7E+03	4.7E+06
Si-32	7.2E-04	7.2E-01	7.2E+02
Sm-147	1.4E-05	1.4E-02	1.4E+01
Sm-151	3.5E-02	3.5E+01	3.5E+04
Sm-153	2.4E-01	2.4E+02	2.4E+05
Sn-113	1.9E-03	1.9E+00	1.9E+03
Sn-117m	2.3E-02	2.3E+01	2.3E+04
Sn-119m	2.8E-02	2.8E+01	2.8E+04
Sn-123	1.8E-02	1.8E+01	1.8E+04
Sn-125	7.2E-03	7.2E+00	7.2E+03
Sn-126	4.7E-06	4.7E-03	4.7E+00
Sr-82	1.9E-03	1.9E+00	1.9E+03
Sr-85	1.9E-03	1.9E+00	1.9E+03
Sr-85m	1.5E+00	1.5E+03	1.5E+06
Sr-87m	1.2E+00	1.2E+03	1.2E+06
Sr-89	2.1E-02	2.1E+01	2.1E+04
Sr-90	5.2E-04	5.2E-01	5.2E+02
Sr-91	1.2E-01	1.2E+02	1.2E+05
Sr-92	2.5E-01	2.5E+02	2.5E+05
Ta-182	4.4E-04	4.4E-01	4.4E+02
Tb-157	2.2E-03	2.2E+00	2.2E+03
Tb-160	8.4E-04	8.4E-01	8.4E+02
Tc-95	9.0E-02	9.0E+01	9.0E+04
Tc-95m	1.4E-03	1.4E+00	1.4E+03
Tc-96	5.6E-03	5.6E+00	5.6E+03
Tc-96m	7.0E-01	7.0E+02	7.0E+05
Tc-97	1.5E-03	1.5E+00	1.5E+03
Tc-97m	7.2E-02	7.2E+01	7.2E+04

<b>Radionuclide</b>	<b>Gaseous form*</b>	<b>Liquid/powder forms</b>	<b>Solid form*</b>
Tc-98	6.4E-06	6.4E-03	6.4E+00
Tc-99	9.0E-03	9.0E+00	9.0E+03
Tc-99m	1.4E+00	1.4E+03	1.4E+06
Tc-101	3.8E+00	3.8E+03	3.8E+06
Te-121	6.0E-03	6.0E+00	6.0E+03
Te-121m	5.3E-04	5.3E-01	5.3E+02
Te-123	1.2E-03	1.2E+00	1.2E+03
Te-123m	2.7E-03	2.7E+00	2.7E+03
Te-125m	1.5E-02	1.5E+01	1.5E+04
Te-127	2.9E+00	2.9E+03	2.9E+06
Te-127m	7.3E-03	7.3E+00	7.3E+03
Te-129	6.5E+00	6.5E+03	6.5E+06
Te-129m	6.1E-03	6.1E+00	6.1E+03
Te-131	9.4E-01	9.4E+02	9.4E+05
Te-131m	1.8E-02	1.8E+01	1.8E+04
Te-132	6.2E-03	6.2E+00	6.2E+03
Te-133	1.2E+00	1.2E+03	1.2E+06
Te-133m	2.9E-01	2.9E+02	2.9E+05
Te-134	4.4E-01	4.4E+02	4.4E+05
Th-226	3.0E-02	3.0E+01	3.0E+04
Th-227	6.4E-05	6.4E-02	6.4E+01
Th-228	2.9E-06	2.9E-03	2.9E+00
Th-229	4.9E-07	4.9E-04	4.9E-01
Th-230	3.2E-06	3.2E-03	3.2E+00
Th-231	8.4E-01	8.4E+02	8.4E+05
Th-232	6.0E-07	6.0E-04	6.0E-01
Th-234	2.0E-02	2.0E+01	2.0E+04
Ti-44	5.2E-06	5.2E-03	5.2E+00
Ti-45	4.0E-01	4.0E+02	4.0E+05
TI-200	4.4E-02	4.4E+01	4.4E+04
TI-201	1.8E-01	1.8E+02	1.8E+05
TI-202	1.0E-02	1.0E+01	1.0E+04

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Tl-204	2.5E-02	2.5E+01	2.5E+04
Tm-170	2.4E-02	2.4E+01	2.4E+04
Tm-171	5.9E-02	5.9E+01	5.9E+04
U-230	5.0E-05	5.0E-02	5.0E+01
U-231	1.4E-01	1.4E+02	1.4E+05
U-232	1.3E-06	1.3E-03	1.3E+00
U-233	7.6E-06	7.6E-03	7.6E+00
U-234	7.6E-06	7.6E-03	7.6E+00
U-235	7.0E-06	7.0E-03	7.0E+00
U-236	8.4E-06	8.4E-03	8.4E+00
U-237	4.7E-02	4.7E+01	4.7E+04
U-238	8.6E-06	8.6E-03	8.6E+00
U-239	8.3E+00	8.3E+03	8.3E+06
U-240	1.8E-01	1.8E+02	1.8E+05
V-48	1.4E-03	1.4E+00	1.4E+03
V-49	1.3E+00	1.3E+03	1.3E+06
W-181	1.1E-02	1.1E+01	1.1E+04
W-185	1.6E-01	1.6E+02	1.6E+05
W-187	1.1E-01	1.1E+02	1.1E+05
W-188	1.0E-02	1.0E+01	1.0E+04
Xe-122	7.6E-02	7.6E+01	7.6E+04
Xe-123	1.6E+00	1.6E+03	1.6E+06
Xe-125	6.0E-01		
Xe-127	7.0E+00		
Xe-129m	7.6E+01		
Xe-131m	2.2E+02		
Xe-133	5.2E+01		
Xe-133m	6.0E+01		
Xe-135	7.6E+00		
Xe-135m	4.2E+00		
Xe-138	9.9E-01		
Y-86	2.8E-02	2.8E+01	2.8E+04

Radionuclide	Gaseous form*	Liquid/powder forms	Solid form*
Y-87	2.3E-02	2.3E+01	2.3E+04
Y-88	2.5E-04	2.5E-01	2.5E+02
Y-90	1.1E-01	1.1E+02	1.1E+05
Y-90m	4.3E-01	4.3E+02	4.3E+05
Y-91	1.8E-02	1.8E+01	1.8E+04
Y-91m	1.6E+00	1.6E+03	1.6E+06
Y-92	7.0E-01	7.0E+02	7.0E+05
Y-93	3.8E-01	3.8E+02	3.8E+05
Yb-169	5.5E-03	5.5E+00	5.5E+03
Yb-175	2.1E-01	2.1E+02	2.1E+05
Zn-62	8.6E-02	8.6E+01	8.6E+04
Zn-65	4.4E-04	4.4E-01	4.4E+02
Zn-69	2.7E+01	2.7E+04	2.7E+07
Zn-69m	2.0E-01	2.0E+02	2.0E+05
Zr-86	2.4E-02	2.4E+01	2.4E+04
Zr-88	2.7E-04	2.7E-01	2.7E+02
Zr-89	1.6E-02	1.6E+01	1.6E+04
Zr-93	2.8E-03	2.8E+00	2.8E+03
Zr-95	6.4E-04	6.4E-01	6.4E+02
Zr-97	4.6E-02	4.6E+01	4.6E+04

\* Radionuclides boiling at 100 °C or less, or exposed to a temperature of 100 °C, must be considered a gas. Capsules containing radionuclides in liquid or powder form can be considered to be solids.

\*\* Mo-99 contained in a generator to produce Technetium-99 can be assumed to be a solid.

### 3. Table of Concentration Levels

(a) Table 2 may be used for determining if facilities are in compliance with the standard.

1. The concentration table as applied to emission estimates can only be used if all releases are from point sources and concentrations have been measured at the stack or vent using EPA-approved methods, and the distance between each stack or vent and the nearest resident is greater than 3 times the diameter of the stack or vent. Procedures provided in Ref. (1) shall be used to determine compliance or exemption from reporting by use of Table 2.

2. The concentration table may be used to determine compliance with the standard based on environmental measurements provided these measurements are made in conformance with the requirements of § 61.107(b)(5).

#### 4. NCRP Screening Model

The procedures described in Reference (4) may be used to determine doses to members of the general public from emissions of radionuclides to the atmosphere. Both the total dose from all radionuclides emitted, and the dose caused by radioactive iodine must be considered in accordance with the procedures in Ref. (1).

#### 5. The COMPLY Computer Code

The COMPLY computer code may be used to determine compliance with subpart I. The compliance model in the COMPLY computer code may be used to determine the dose to members of the general public from emissions of radionuclides to the atmosphere. The EPA may add radionuclides to all or any part of COMPLY to cover radionuclides that may be used by the regulated community.

**TABLE 2—CONCENTRATION LEVELS FOR ENVIRONMENTAL COMPLIANCE**

Radionuclide	Concentration (Ci/m <sup>3</sup> )	Radionuclide	Concentration (Ci/m <sup>3</sup> )
Ac-225	9.1E-14	Bi-207	1.0E-14
Ac-227	1.6E-16	Bi-210	2.9E-13
Ac-228	3.7E-12	Bi-212	5.6E-11
Ag-106	1.9E-09	Bi-213	7.1E-11
Ag-106m	1.2E-12	Bi-214	1.4E-10
Ag-108m	7.1E-15	Bk-249	5.6E-13
Ag-110m	9.1E-14	Bk-250	9.1E-11
Ag-111	2.5E-12	Br-77	4.2E-11
Al-26	4.8E-15	Br-80	1.4E-08
Am-241	1.9E-15	Br-80m	1.8E-09
Am-242	1.5E-11	Br-82	1.2E-11
Am-242m	2.0E-15	Br-83	1.2E-08
Am-243	1.8E-15	Br-84	6.7E-10
Am-244	4.0E-11	C-11	1.5E-09
Am-245	8.3E-09	C-14	1.0E-11
Am-246	1.2E-09	Ca-41	4.2E-13
Ar-37	1.6E-03	Ca-45	1.3E-12
Ar-41	1.7E-09	Ca-47	2.4E-12
As-72	2.4E-11	Cd-109	5.9E-13
As-73	1.1E-11	Cd-113	9.1E-15
As-74	2.2E-12	Cd-113m	1.7E-14
As-76	5.0E-11	Cd-115	1.6E-11

Radionuclide	Concentration (Ci/m <sup>3</sup> )	Radionuclide	Concentration (Ci/m <sup>3</sup> )
As-77	1.6E-10	Cd-115m	8.3E-13
At-211	1.1E-11	Cd-117	6.7E-11
Au-193	3.8E-10	Cd-117m	1.6E-10
Au-194	3.2E-11	Ce-139	2.6E-12
Au-195	3.1E-12	Ce-141	6.3E-12
Au-198	2.1E-11	Ce-143	3.0E-11
Au-199	4.8E-11	Ce-144	6.2E-13
Ba-131	7.1E-12	Cf-248	1.8E-14
Ba-133	5.9E-14	Cf-249	1.4E-15
Ba-133m	5.9E-11	Cf-250	3.2E-15
Ba-135m	1.8E-10	Cf-251	1.4E-15
Ba-139	5.6E-09	Cf-252	5.6E-15
Ba-140	1.3E-12	Cf-253	3.1E-13
Ba-141	1.4E-09	Cf-254	3.0E-15
Ba-142	1.3E-09	Cl-36	2.7E-15
Be-7	2.3E-11	Cl-38	7.7E-10
Be-10	1.6E-12	Cm-242	5.3E-14
Bi-206	2.3E-12	Cm-243	2.6E-15
Cm-244	3.3E-15	Eu-156	1.9E-12
Cm-245	1.8E-15	F-18	6.7E-10
Cm-246	1.9E-15	Fe-52	5.6E-11
Cm-247	1.9E-15	Fe-55	9.1E-12
Cm-248	5.0E-16	Fe-59	6.7E-13
Cm-249	3.7E-09	Fm-254	2.0E-11
Cm-250	9.1E-17	Fm-255	4.3E-12
Co-56	1.8E-13	Fr-223	3.3E-11
Co-57	1.3E-12	Ga-66	6.2E-11
Co-58	6.7E-13	Ga-67	7.1E-11
Co-58m	1.2E-10	Ga-68	9.1E-10
Co-60	1.7E-14	Ga-72	3.8E-11
Co-60m	4.3E-09	Gd-152	5.0E-15
Co-61	4.5E-09	Gd-153	2.1E-12



Radionuclide	Concentration (Ci/m <sup>3</sup> )	Radionuclide	Concentration (Ci/m <sup>3</sup> )
Cr-49	1.1E-09	Gd-159	2.9E-10
Cr-51	3.1E-11	Ge-68	2.0E-13
Cs-129	1.4E-10	Ge-71	2.4E-10
Cs-131	3.3E-11	Ge-77	1.0E-10
Cs-132	4.8E-12	H-3	1.5E-09
Cs-134	2.7E-14	Hf-181	1.9E-12
Cs-134m	1.7E-10	Hg-193m	1.0E-10
Cs-135	4.0E-13	Hg-197	8.3E-11
Cs-136	5.3E-13	Hg-197m	1.1E-10
Cs-137	1.9E-14	Hg-203	1.0E-12
Cs-138	5.3E-10	Ho-166	7.1E-11
Cu-61	4.8E-10	Ho-166m	7.1E-15
Cu-64	5.3E-10	I-123	4.3E-10
Cu-67	5.0E-11	I-124	6.2E-13
Dy-157	5.0E-10	I-125	1.2E-13
Dy-165	6.7E-09	I-126	1.1E-13
Dy-166	1.1E-11	I-128	1.1E-08
Er-169	2.9E-11	I-129	9.1E-15
Er-171	4.0E-10	I-130	4.5E-11
Es-253	2.4E-13	I-131	2.1E-13
Es-254	2.0E-14	I-132	2.3E-10
Es-254m	1.8E-12	I-133	2.0E-11
Eu-152	2.0E-14	I-134	3.8E-10
Eu-152m	3.6E-10	I-135	1.2E-10
Eu-154	2.3E-14	In-111	3.6E-11
Eu-155	5.9E-13	In-113m	2.5E-09
In-114m	9.1E-13	Nb-95	2.2E-12
In-115	7.1E-14	Nb-95m	1.4E-11
In-115m	1.6E-09	Nb-96	2.4E-11
In-116m	4.2E-10	Nb-97	1.2E-09
In-117	1.6E-09	Nd-147	7.7E-12
In-117m	9.1E-11	Nd-149	7.1E-10

Radionuclide	Concentration (Ci/m <sup>3</sup> )	Radionuclide	Concentration (Ci/m <sup>3</sup> )
Ir-190	2.6E-12	Ni-56	1.7E-12
Ir-192	9.1E-13	Ni-57	1.8E-11
Ir-194	1.1E-10	Ni-59	1.5E-11
Ir-194m	1.7E-13	Ni-63	1.4E-11
K-40	2.7E-14	Ni-65	8.3E-10
K-42	2.6E-10	Np-235	2.5E-11
K-43	6.2E-11	Np-237	1.2E-15
K-44	5.9E-10	Np-238	1.4E-11
Kr-79	8.3E-09	Np-239	3.8E-11
Kr-81	2.1E-07	Np-240	7.7E-10
Kr-83m	2.3E-05	Np-240m	5.6E-09
Kr-85	1.0E-06	Os-185	1.0E-12
Kr-85m	1.3E-08	Os-191m	2.9E-10
Kr-87	2.4E-09	Os-191	1.1E-11
Kr-88	5.0E-10	Os-193	9.1E-11
La-140	1.2E-11	P-32	3.3E-13
La-141	7.7E-10	P-33	2.4E-12
La-142	2.7E-10	Pa-230	3.2E-13
Lu-177	2.4E-11	Pa-231	5.9E-16
Lu-177m	3.6E-13	Pa-233	4.8E-12
Mg-28	1.5E-11	Pa-234	1.1E-10
Mn-52	2.8E-12	Pb-203	6.2E-11
Mn-52m	6.2E-10	Pb-205	5.6E-12
Mn-53	1.5E-11	Pb-209	1.3E-08
Mn-54	2.8E-13	Pb-210	2.8E-15
Mn-56	2.9E-10	Pb-211	1.4E-10
Mo-93	1.1E-12	Pb-212	6.3E-12
Mo-99	1.4E-11	Pb-214	1.2E-10
Mo-101	1.0E-09	Pd-103	3.8E-11
Na-22	2.6E-14	Pd-107	3.1E-11
Na-24	2.6E-11	Pd-109	4.8E-10
Nb-90	2.6E-11	Pm-143	9.1E-13

<b>Radionuclide</b>	<b>Concentration (Ci/m<sup>3</sup>)</b>	<b>Radionuclide</b>	<b>Concentration (Ci/m<sup>3</sup>)</b>
Nb-93m	1.0E-11	Pm-144	1.3E-13
Nb-94	7.1E-15	Pm-145	6.2E-13
Pm-146	5.3E-14	Re-184m	3.7E-13
Pm-147	1.1E-11	Re-186	1.8E-11
Pm-148	5.0E-12	Re-187	2.6E-10
Pm-148m	6.7E-13	Re-188	1.7E-10
Pm-149	4.2E-11	Rh-103m	2.1E-07
Pm-151	7.1E-11	Rh-105	1.3E-10
Po-210	7.1E-15	Ru-97	6.7E-11
Pr-142	1.1E-10	Ru-103	2.6E-12
Pr-143	7.1E-12	Ru-105	2.8E-10
Pr-144	1.8E-08	Ru-106	3.4E-13
Pt-191	4.3E-11	S-35	1.3E-12
Pt-193	1.8E-11	Sb-117	2.4E-09
Pt-193m	4.8E-11	Sb-122	1.4E-11
Pt-195m	3.2E-11	Sb-124	5.3E-13
Pt-197	4.0E-10	Sb-125	1.6E-13
Pt-197m	2.6E-09	Sb-126	1.4E-12
Pu-236	5.9E-15	Sb-126m	9.1E-10
Pu-237	1.9E-11	Sb-127	7.1E-12
Pu-238	2.1E-15	Sb-129	7.7E-11
Pu-239	2.0E-15	Sc-44	1.7E-10
Pu-240	2.0E-15	Sc-46	4.2E-13
Pu-241	1.0E-13	Sc-47	3.8E-11
Pu-242	2.0E-15	Sc-48	9.1E-12
Pu-243	4.2E-09	Sc-49	1.2E-08
Pu-244	2.0E-15	Se-73	1.7E-10
Pu-245	2.1E-10	Se-75	1.7E-13
Pu-246	2.2E-12	Se-79	1.1E-13
Ra-223	4.2E-14	Si-31	5.6E-09
Ra-224	1.5E-13	Si-32	3.4E-14
Ra-225	5.0E-14	Sm-147	1.4E-14

<b>Radionuclide</b>	<b>Concentration (Ci/m<sup>3</sup>)</b>	<b>Radionuclide</b>	<b>Concentration (Ci/m<sup>3</sup>)</b>
Ra-226	3.3E-15	Sm-151	2.1E-11
Ra-228	5.9E-15	Sm-153	5.9E-11
Rb-81	5.0E-10	Sn-113	1.4E-12
Rb-83	3.4E-13	Sn-117m	5.6E-12
Rb-84	3.6E-13	Sn-119m	5.3E-12
Rb-86	5.6E-13	Sn-123	1.1E-12
Rb-87	1.6E-13	Sn-125	1.7E-12
Rb-88	2.1E-09	Sn-126	5.3E-15
Rb-89	7.1E-10	Sr-82	6.2E-13
Re-184	1.5E-12	Sr-85	1.8E-12
Sr-85m	1.6E-09	Th-232	6.2E-16
Sr-87m	1.4E-09	Th-234	2.2E-12
Sr-89	1.8E-12	Ti-44	6.2E-15
Sr-90	1.9E-14	Ti-45	4.8E-10
Sr-91	9.1E-11	Tl-200	4.5E-11
Sr-92	2.9E-10	Tl-201	1.0E-10
Ta-182	4.5E-13	Tl-202	5.0E-12
Tb-157	2.5E-12	Tl-204	1.2E-12
Tb-160	7.7E-13	Tm-170	3.3E-12
Tc-95	1.0E-10	Tm-171	2.6E-11
Tc-95m	1.4E-12	U-230	1.5E-14
Tc-96	5.6E-12	U-231	4.2E-11
Tc-96m	6.7E-10	U-232	1.3E-15
Tc-97	7.1E-13	U-233	7.1E-15
Tc-97m	7.1E-12	U-234	7.7E-15
Tc-98	6.7E-15	U-235	7.1E-15
Tc-99	1.4E-13	U-236	7.7E-15
Tc-99m	1.7E-09	U-237	1.0E-11
Tc-101	4.5E-09	U-238	8.3E-15
Te-121	1.0E-12	U-239	4.3E-09
Te-121m	1.2E-13	U-240	1.3E-10
Te-123	1.4E-13	V-48	1.0E-12

Radionuclide	Concentration (Ci/m <sup>3</sup> )	Radionuclide	Concentration (Ci/m <sup>3</sup> )
Te-123m	2.0E-13	V-49	1.6E-10
Te-125m	3.6E-13	W-181	6.7E-12
Te-127	1.0E-09	W-185	2.6E-12
Te-127m	1.5E-13	W-187	7.7E-11
Te-129	7.7E-09	W-188	5.3E-13
Te-129m	1.4E-13	Xe-122	9.1E-11
Te-131	9.1E-11	Xe-123	1.6E-09
Te-131m	1.0E-12	Xe-125	1.1E-11
Te-132	7.1E-13	Xe-127	8.3E-09
Te-133	9.1E-10	Xe-129m	9.1E-08
Te-133m	2.2E-10	Xe-131m	2.6E-07
Te-134	5.3E-10	Xe-133	6.2E-08
Th-226	3.4E-11	Xe-133m	7.1E-08
Th-227	3.8E-14	Xe-135	9.1E-09
Th-228	3.1E-15	Xe-135m	5.0E-09
Th-229	5.3E-16	Xe-138	1.2E-09
Th-230	3.4E-15	Y-86	3.0E-11
Th-231	2.9E-10	Y-87	1.7E-11
Y-88	2.7E-13	Zn-65	9.1E-14
Y-90	1.3E-11	Zn-69	3.2E-08
Y-90m	1.9E-10	Zn-69m	1.7E-10
Y-91	2.1E-12	Zr-86	2.4E-11
Y-91m	1.3E-09	Zr-88	3.1E-13
Y-92	8.3E-10	Zr-89	1.3E-11
Y-93	2.9E-10	Zr-93	2.6E-12
Yb-169	3.7E-12	Zr-95	6.7E-13
Yb-175	4.3E-11	Zr-97	3.8E-11
Zn-62	9.1E-11		

## 6. References

(1) Environmental Protection Agency, "A Guide for Determining Compliance with the Clean Air Act Standards for Radionuclides Emissions from NRC-Licensed and Non-DOE Federal Facilities", EPA 520/1-89-002, October 1989.

(2) Environmental Protection Agency, "User's Guide for the COMPLY Code", EPA 520/1-89-003, October 1989.

(3) Environmental Protection Agency, "Background Information Document: Procedures Approved for Demonstrating Compliance with 40 CFR Part 61, Subpart I", EPA 520/1-89-001, January 1989.

(4) National Council on Radiation Protection and Measurement, "Screening Techniques for Determining Compliance with Environmental Standards" NCRP Commentary No. 3, Revision of January 1989 with addendum of October, 1989.

[54 FR 51711, Dec. 15, 1989]

## Indiana Department of Environmental Management Office of Air Quality

### Attachment G to a Part 70 Operating Permit

Source Description and Location
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

40 CFR 63, Subpart ZZZZ
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**Subpart ZZZZ - National Emission 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.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

#### **§ 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 that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(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 that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(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;

(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; 78 FR 6700, Jan. 30, 2013]

#### **§ 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, operating limitations and other requirements 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, operating limitations, and other requirements 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, operating limitations, and other requirements 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; 78 FR 6701, Jan. 30, 2013]

## 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 and other requirements 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 and other requirements 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.

[78 FR 6701, Jan. 30, 2013]

**§ 63.6603 What emission limitations, operating limitations, and other requirements 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 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. 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.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

**§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?**

(a) 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.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

**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, operating limitations, and other requirements 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, as amended at 78 FR 6702, Jan. 30, 2013]

## 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. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(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, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (\text{Eq. 1})$$

Where:

$C_i$  = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

$C_o$  = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, 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 ( $\text{CO}_2$ ). If pollutant concentrations are to be corrected to 15 percent oxygen and  $\text{CO}_2$  concentration is measured in lieu of oxygen concentration measurement, a  $\text{CO}_2$  correction factor is needed. Calculate the  $\text{CO}_2$  correction 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:

$$F_o = \frac{0.209 F_d}{F_c} \quad (\text{Eq. 2})$$

Where:

$F_o$  = Fuel factor based on the ratio of oxygen volume to the ultimate  $\text{CO}_2$  volume 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,  $\text{dsm}^3/\text{J}$  ( $\text{dscf}/10^6 \text{ Btu}$ ).

$F_c$  = Ratio of the volume of CO<sub>2</sub> produced to the gross calorific value of the fuel from Method 19, dsm<sup>3</sup> /J (dscf/10<sup>6</sup> Btu)

(ii) Calculate the CO<sub>2</sub> correction factor for correcting measurement data to 15 percent O<sub>2</sub> , as follows:

$$X_{CO_2} = \frac{5.9}{F_O} \quad (\text{Eq. 3})$$

Where:

$X_{CO_2}$  = CO<sub>2</sub> correction factor, percent.

5.9 = 20.9 percent O<sub>2</sub> —15 percent O<sub>2</sub> , the defined O<sub>2</sub> correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O<sub>2</sub> using CO<sub>2</sub> as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad (\text{Eq. 4})$$

Where:

$C_{adj}$  = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O<sub>2</sub>.

$C_d$  = Measured concentration of CO, THC, or formaldehyde, uncorrected.

$X_{CO_2}$  = CO<sub>2</sub> correction factor, percent.

%CO<sub>2</sub> = Measured CO<sub>2</sub> concentration 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; 78 FR 6702, Jan. 30, 2013]

#### **§ 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 O<sub>2</sub> or CO<sub>2</sub> according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(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<sub>2</sub> concentration.

(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 (6) 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)(ii) 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 stationary RICE located at an area 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.

(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 (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 that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(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 business 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 business 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 business 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 business 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; 78 FR 6703, Jan. 30, 2013]

**§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?**

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement 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.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O<sub>2</sub> using one of the O<sub>2</sub> measurement methods specified in Table 4 of this subpart. Measurements to determine O<sub>2</sub> concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O<sub>2</sub> emissions simultaneously at the inlet and outlet of the control device.



[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

### **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, operating limitations, and other requirements?**

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements 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) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O<sub>2</sub> using one of the O<sub>2</sub> measurement methods specified in Table 4 of this subpart. Measurements to determine O<sub>2</sub> concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O<sub>2</sub> emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(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) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. 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 calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, 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.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[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; 78 FR 6704, Jan. 30, 2013]

## **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).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

#### **§ 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.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.



(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) ( [www.epa.gov/cdx](http://www.epa.gov/cdx) ). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

### **§ 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) through (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 engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(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; 78 FR 6706, Jan. 30, 2013]

**§ 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:

*Alaska Railbelt Grid* means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

*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.

*Backup power for renewable energy* means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

*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 of 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<sub>2</sub>.

*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 reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. 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.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. 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.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

*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<sub>2</sub>.

*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 ( $\text{NO}_x$ ) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen,  $\text{NO}_x$ , CO, and volatile organic compounds (VOC) into  $\text{CO}_2$ , 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  $\text{C}_3\text{H}_8$ .

*Remote stationary RICE* means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

*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<sub>x</sub> (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 P 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; 78 FR 6706, Jan. 30, 2013]

**Table 1 a to 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. <sup>1</sup>
	b. Limit the concentration of formaldehyde in	

<b>For each . . .</b>	<b>You must meet the following emission limitation, except during periods of startup . . .</b>	<b>During periods of startup you must . . .</b>
	the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub>	

<sup>1</sup>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]

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**Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major 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:

<b>For each . . .</b>	<b>You must meet the following operating limitation, except during periods of startup . . .</b>
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions 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 existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub> and using NSCR;	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 or equal to 750 °F and less than or equal to 1250 °F. <sup>1</sup>
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions 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	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O <sub>2</sub> and not using NSCR.	

<sup>1</sup> Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

**Table 2 a to 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 <sub>2</sub> . 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 <sub>2</sub> until 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. <sup>1</sup>
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O <sub>2</sub>	
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 <sub>2</sub>	

<sup>1</sup> 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 2 b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI 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 CI Stationary RICE >500 HP**

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 CI 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; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
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1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde 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. <sup>1</sup>
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce 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 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. <sup>1</sup>
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

<sup>1</sup> Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

**Table 2 c to 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 <sup>1</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first. <sup>2</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	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. <sup>3</sup>
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. <sup>2</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
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 <sub>2</sub> .	
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 <sub>2</sub> ; 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 <sub>2</sub> ; or b. Reduce CO emissions by	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE. <sup>1</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>2</sup> b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
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; <sup>2</sup> b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
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; <sup>2</sup> b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	
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	

<b>For each . . .</b>	<b>You must meet the following requirement, except during periods of startup . . .</b>	<b>During periods of startup you must . . .</b>
	less at 15 percent O <sub>2</sub> .	
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 <sub>2</sub> .	
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 <sub>2</sub> .	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O <sub>2</sub> .	

<sup>1</sup> 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.

<sup>2</sup> Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

<sup>3</sup> Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

**Table 2 d to 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:

<b>For each . . .</b>	<b>You must meet the following requirement, except during periods of startup . . .</b>	<b>During periods of startup you must . . .</b>
1. Non-Emergency, non-black start CI	a. Change oil and filter	Minimize the engine's time spent at

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
stationary RICE $\leq 300$ HP	every 1,000 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	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.
2. Non-Emergency, non-black start CI stationary RICE $300 < \text{HP} \leq 500$	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O <sub>2</sub> ; 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 <sub>2</sub> ; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE. <sup>2</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	



For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
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. <sup>2</sup>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; 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; <sup>1</sup>	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; 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; <sup>1</sup>	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first,	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. 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; <sup>1</sup>	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; <sup>1</sup>	
	b. Inspect spark plugs every 2,160 hours of	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; <sup>1</sup> b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

<sup>1</sup> Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

<sup>2</sup> 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.

[78 FR 6709, Jan. 30, 2013]

**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:

<b>For each . . .</b>	<b>Complying with the requirement to . . .</b>	<b>You must . . .</b>
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually. <sup>1</sup>
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually. <sup>1</sup>
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually. <sup>1</sup>
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

<sup>1</sup> 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.

[78 FR 6711, Jan. 30, 2013]

**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:

<b>For each . . .</b>	<b>Complying with the requirement to . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>	<b>According to the following requirements . . .</b>
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Measure the O <sub>2</sub> 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 D6522-00 (Reapproved 2005). <sup>a c</sup>	(a) Measurements to determine O <sub>2</sub> must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet	(1) ASTM D6522-00 (Reapproved 2005) <sup>a b c</sup> or	(a) The CO concentration must be

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		of the control device	Method 10 of 40 CFR part 60, appendix A	at 15 percent O <sub>2</sub> , 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 <sub>2</sub> 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 D6522-00 (Reapproved 2005). <sup>a</sup>	(a) measurements to determine O <sub>2</sub> concentration must be made at the same time as the measurements for formaldehyde or THC 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. <sup>a</sup>	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, 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, <sup>a</sup> 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 <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A	(a) THC concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
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 <sub>2</sub> concentration of the	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix	(a) measurements to determine

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		stationary RICE exhaust at the sampling port location; and	A, or ASTM Method D6522-00 (Reapproved 2005). <sup>a</sup>	O <sub>2</sub> concentration must be made at the same time and location as the measurements for formaldehyde or CO 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. <sup>a</sup>	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO 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, <sup>a</sup> 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 <sub>2</sub> , 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), <sup>a</sup> <sup>c</sup> Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03. <sup>a</sup>	(a) CO concentration must be at 15 percent O <sub>2</sub> , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

<sup>a</sup> Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

<sup>b</sup> You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.

<sup>c</sup> ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.

[78 FR 6711, Jan. 30, 2013]

**Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements**

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, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	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, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	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 major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	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 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, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	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

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		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, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O <sub>2</sub> or CO <sub>2</sub> 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, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O <sub>2</sub> or CO <sub>2</sub> at the 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 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	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, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the



For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		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	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 or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; 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. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP 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. The average formaldehyde concentration, corrected to 15 percent O <sub>2</sub> , 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.
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 $250 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP 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. The average formaldehyde concentration, corrected to 15 percent O <sub>2</sub> , 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

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		initial performance test.
11. Existing non-emergency stationary RICE $100 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency stationary CI RICE $300 < \text{HP} \leq 500$ located at an area source of HAP	a. Reduce CO 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.
12. Existing non-emergency stationary RICE $100 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency stationary CI RICE $300 < \text{HP} \leq 500$ 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 $\text{O}_2$ , dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE $>500$ HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent $\text{O}_2$ ;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE $>500$ HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent $\text{O}_2$ , or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

**Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements**

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 <sup>a</sup> ; 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-emergency CI stationary RICE >500 HP located at a major source of HAP	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 <sup>a</sup> ; 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.
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, and existing non-emergency stationary CI RICE >500 HP	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

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		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 source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) 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 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, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent. <sup>a</sup>
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	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit <sup>a</sup> ; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
major source of HAP	oxidation catalyst or NSCR	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 <sup>a</sup> ; 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 stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source	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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
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, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE		
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	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	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	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

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	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	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	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.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O <sub>2</sub> ; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O <sub>2</sub> , or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

<sup>a</sup> 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.

[78 FR 6715, Jan. 30, 2013]

#### 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 $100 \leq \text{HP} \leq 500$ 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; 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 $250 \leq \text{HP} \leq 500$ 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	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.
		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	i. Semiannually according to the requirements in § 63.6650(b).
		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).
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	i. See item 2.a.i.

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
		suspected with the meters.	
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. annually according to the requirements in § 63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

**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.	

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§ 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.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 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	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 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	

General provisions citation	Subject of citation	Applies to subpart	Explanation
		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 data	No	Subpart ZZZZ does not contain 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.	

<b>General provisions citation</b>	<b>Subject of citation</b>	<b>Applies to subpart</b>	<b>Explanation</b>
§ 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	Except that the most recent 2 years of data do not have to be retained on site.
§ 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.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 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, as amended at 78 FR 6720, Jan. 30, 2013]

## **Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines**

### **1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?**

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O<sub>2</sub>) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

#### *1.1 Analytes. What does this protocol determine?*

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O<sub>2</sub>).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O <sub>2</sub> )	7782-44-7	

*1.2 Applicability. When is this protocol acceptable?*

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

*1.3 Data Quality Objectives. How good must my collected data be?*

Refer to Section 13 to verify and document acceptable analyzer performance.

*1.4 Range. What is the targeted analytical range for this protocol?*

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O<sub>2</sub>, or no more than twice the permitted CO level.

*1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?*

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

## 2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O<sub>2</sub> gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

## 3.0 DEFINITIONS

**3.1 Measurement System.** The total equipment required for the measurement of CO and O<sub>2</sub> concentrations. The measurement system consists of the following major subsystems:

**3.1.1 Data Recorder.** A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

**3.1.2 Electrochemical (EC) Cell.** A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.



**3.1.3 Interference Gas Scrubber.** A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

**3.1.4 Moisture Removal System.** Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

**3.1.5 Sample Interface.** The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

**3.2 Nominal Range.** The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

**3.3 Calibration Gas.** A vendor certified concentration of a specific analyte in an appropriate balance gas.

**3.4 Zero Calibration Error.** The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

**3.5 Up-Scale Calibration Error.** The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

**3.6 Interference Check.** A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

**3.7 Repeatability Check.** A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

**3.8 Sample Flow Rate.** The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

**3.9 Sampling Run.** A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O<sub>2</sub> and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre-sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

**3.10 Sampling Day.** A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

*3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check.* The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

*3.12 Performance-Established Configuration.* The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

#### 4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO<sub>2</sub> are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

#### 5.0 SAFETY. [RESERVED]

#### 6.0 EQUIPMENT AND SUPPLIES.

##### *6.1 What equipment do I need for the measurement system?*

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

##### *6.2 Measurement System Components.*

*6.2.1 Sample Probe.* A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

*6.2.2 Sample Line.* Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

*6.2.3 Calibration Assembly (optional).* A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

*6.2.4 Particulate Filter (optional).* Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

*6.2.5 Sample Pump.* A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

*6.2.8 Sample Flow Rate Monitoring.* An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

*6.2.9 Sample Gas Manifold (optional).* A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

**6.2.10 EC cell.** A device containing one or more EC cells to determine the CO and O<sub>2</sub> concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

**6.2.11 Data Recorder.** A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O<sub>2</sub>; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

**6.2.12 Interference Gas Filter or Scrubber.** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

## 7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

**7.1 Calibration Gases.** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O<sub>2</sub>. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within  $\pm 5$  percent of the label value. Dry ambient air (20.9 percent O<sub>2</sub>) is acceptable for calibration of the O<sub>2</sub> cell. If needed, any lower percentage O<sub>2</sub> calibration gas must be a mixture of O<sub>2</sub> in nitrogen.

**7.1.1 Up-Scale CO Calibration Gas Concentration.** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

### 7.1.2 Up-Scale O<sub>2</sub> Calibration Gas Concentration.

Select an O<sub>2</sub> gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O<sub>2</sub>. When the average exhaust gas O<sub>2</sub> readings are above 6 percent, you may use dry ambient air (20.9 percent O<sub>2</sub>) for the up-scale O<sub>2</sub> calibration gas.

**7.1.3 Zero Gas.** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO<sub>2</sub>).

## 8.0 SAMPLE COLLECTION AND ANALYSIS

### 8.1 Selection of Sampling Sites.

**8.1.1 Control Device Inlet.** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

**8.1.2 Exhaust Gas Outlet.** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling

extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

**8.2 Stack Gas Collection and Analysis.** Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O<sub>2</sub> concentrations.

**8.3 EC Cell Rate.** Maintain the EC cell sample flow rate so that it does not vary by more than  $\pm 10$  percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than  $\pm 3$  percent, as instructed by the EC cell manufacturer.

## 9.0 QUALITY CONTROL (RESERVED)

## 10.0 CALIBRATION AND STANDARDIZATION

**10.1 Pre-Sampling Calibration.** Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

**10.1.1 Zero Calibration.** For both the O<sub>2</sub> and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

**10.1.2 Zero Calibration Tolerance.** For each zero gas introduction, the zero level output must be less than or equal to  $\pm 3$  percent of the up-scale gas value or  $\pm 1$  ppm, whichever is less restrictive, for the CO channel and less than or equal to  $\pm 0.3$  percent O<sub>2</sub> for the O<sub>2</sub> channel.

**10.1.3 Up-Scale Calibration.** Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

**10.1.4 Up-Scale Calibration Error.** The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to  $\pm 5$  percent or  $\pm 1$  ppm for

CO or  $\pm 0.5$  percent O<sub>2</sub>, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to  $\pm 2$  percent or  $\pm 1$  ppm for CO or  $\pm 0.5$  percent O<sub>2</sub>, whichever is less restrictive, respectively.

**10.2 Post-Sampling Calibration Check.** Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

## 11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

## 12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O<sub>2</sub> concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

## 13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

**13.1 Measurement Data Phase Performance Check.** Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is  $\pm 2$  percent, or  $\pm 1$  ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

*Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than  $\pm 2$  percent or  $\pm 1$  ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).*

**13.2 Interference Check.** Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO<sub>2</sub> gas standards that are generally recognized as representative of diesel-fueled engine NO and NO<sub>2</sub> emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

**13.2.1 Interference Response.** The combined NO and NO<sub>2</sub> interference response should be less than or equal to  $\pm 5$  percent of the up-scale CO calibration gas concentration.

**13.3 Repeatability Check.** Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

*13.3.1 Repeatability Check Procedure.* Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

*13.3.2 Repeatability Check Calculations.* Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than  $\pm 3$  percent or  $\pm 1$  ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) "Development of an Electrochemical Cell Emission Analyzer Test Protocol", Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) "Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers", EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) "ICAC Test Protocol for Periodic Monitoring", EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) "Code of Federal Regulations", Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

**TABLE 1: APPENDIX A—SAMPLING RUN DATA.**

Facility_____		Engine I.D._____				Date_____					
Run Type:	( )		( )		( )		( )		( )		
(X)	Pre-Sample Calibration		Stack Gas Sample				Post-Sample Cal. Check			Repeatability Check	
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O <sub>2</sub>	CO	O <sub>2</sub>	CO	O <sub>2</sub>	CO	O <sub>2</sub>	CO			
Sample Cond. Phase											
"											
"											
"											
"											
Measurement Data Phase											
"											
"											
"											
"											
"											
"											
Mean											
Refresh Phase											
"											
"											
"											
"											

[78 FR 6721, Jan. 30, 2013]

**Indiana Department of Environmental Management  
Office of Air Quality**

**Addendum to the Technical Support Document (TSD)  
for a PSD/New Source Construction and Part 70 Operating Permit**

<b>Source Background and Description</b>
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<b>Source Name:</b>	<b>Midwest Fertilizer Corporation</b>
<b>Source Location:</b>	<b>Intersection Old SR 69 and Mackey Ferry Road East Mt. Vernon, Indiana 47620</b>
<b>County:</b>	<b>Posey County</b>
<b>SIC Code:</b>	<b>2873 (Nitrogenous Fertilizers)</b>
<b>Permit Number:</b>	<b>T129-33576-00059</b>
<b>Permit Reviewer:</b>	<b>David Matousek</b>

<b>Public Notice Information</b>
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On January 22, 2014, the Office of Air Quality (OAQ) had a notice published in the Mount Vernon Democrat in Mt. Vernon, Indiana stating that Midwest Fertilizer Corporation applied for a PSD/New Source Construction and Part 70 Operating Permit. This PSD/New Source Construction and Part 70 Operating Permit would allow Midwest Fertilizer Corporation to construct and operate a new stationary nitrogen fertilizer manufacturing facility.

This notice stated that the OAQ proposed to issue a PSD/New Source Construction and Part 70 Operating Permit for this operation. The notice provided information on how the public could review the proposed permit and other documentation and informed interested parties that there was a period of thirty days to provide comments on the issuance of the permit. Finally, this notice invited the public to attend a public hearing and public meeting at the Mt. Vernon High School located at 700 Harriett Street in Mt. Vernon, Indiana on February 26, 2014.

On February 26, 2014, IDEM, OAQ conducted a public meeting followed by a public hearing at the Mt. Vernon High School. IDEM, OAQ staff was available to accept formal comments and answer questions from the public on the proposed permit. Approximately 80 residents attended the public hearing and public meeting.

<b>Comments and IDEM's Responses</b>
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IDEM, OAQ received written comments during the public comment period and testimony from the public during the public hearing. IDEM, OAQ has summarized and consolidated the comments received during the public comment period and the public hearing. IDEM, OAQ combined comments dealing with similar issues and provided a response on the issue in question. If a change was required to the permit because of the comment, IDEM's response shows the revision immediately following the comment, with new text shown in **bold** and deleted text shown in ~~strikeout~~. IDEM, OAQ did not revise the Technical Support Document (TSD) because; the TSD serves a historical purpose. IDEM, OAQ documents changes due to comments received during the public comment period with this Addendum to the Technical Support Document (ATSD).



## U.S. EPA Comments:

### U.S. EPA Comment No. 1:

#### Greenhouse Gas BACT – Turbines and Auxiliary Boilers

The Greenhouse Gas (GHG) Best Available Control Technology (BACT) analysis for the combustion turbines and auxiliary boilers do not include a statement explaining why Carbon Dioxide (CO<sub>2</sub>) serves as a sufficient surrogate for total CO<sub>2</sub> equivalent (CO<sub>2</sub>e) emissions. For the combustion turbines and auxiliary boilers, the permit should either address GHG limits in CO<sub>2</sub>e or on an individual gas mass basis (i.e., for CO<sub>2</sub>, methane, and Nitrous Oxide (N<sub>2</sub>O)), or provide an explanation of why CO<sub>2</sub> emissions sufficiently represent CO<sub>2</sub>e emissions.

#### IDEM Response

IDEM, OAQ used CO<sub>2</sub> as a surrogate for CO<sub>2</sub>e in establishing the Best Available Control Technology (BACT) determination for greenhouse gases (GHGs) for the combustion turbines and auxiliary boilers. CO<sub>2</sub> was selected as a surrogate for CO<sub>2</sub>e emissions for two reasons. First, the non-CO<sub>2</sub> point source GHG emissions from fuel combustion have a direct relationship to and are proportionate to fuel use and the associated CO<sub>2</sub> emissions. Thus, limitations on fuel use will directly and proportionately limit both CO<sub>2</sub> and non-CO<sub>2</sub> point source GHG emissions. Second, the non-CO<sub>2</sub> point source GHG emissions from fuel combustion are minimal. The tables below illustrate the second point:

Boiler Emissions at PTE			
Pollutant	PTE (TPY)	PTE (TPY as CO <sub>2</sub> e)	Mass % of Total Emissions (CO <sub>2</sub> e)
CO <sub>2</sub>	111,911	111,911	99.89%
CH <sub>4</sub>	2.11	52.75	0.05%
N <sub>2</sub> O	0.21	62.58	0.06%
Total	NA	112,026	100%

Turbine Emissions			
Pollutant	PTE (TPY)	PTE (TPY as CO <sub>2</sub> e)	Mass % of Total Emissions (CO <sub>2</sub> e)
CO <sub>2</sub>	144,890	144,890	99.90%
CH <sub>4</sub>	2.73	68.25	0.05%
N <sub>2</sub> O	0.27	80.46	0.05%
Total	NA	145,039	100%

IDEM, OAQ will add an explanation to the GHG BACT determinations for the combustion turbines and auxiliary boilers to justify the use of CO<sub>2</sub> as a surrogate for all GHGs. Appendix B to the Technical Support Document (TSD) BACT Analysis, page 109 of 197 has been revised as shown below:

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the open-simple cycle combustion turbines (EU-013A/B) as: \*\*\*\*\*

(e) \*\*\*\*\*

**This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.**

Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Open-Simple Cycle Combustion Turbines (EU-013A/B)

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Appendix B to the Technical Support Document (TSD) BACT Analysis, page 126 of 197 has been revised as shown below:

Step 5: Select BACT

\*\*\*\*\*

- (f) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

**This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.**

Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Auxiliary Boilers (EU-012A/B/C)

\*\*\*\*\*

**U.S. EPA Comment No. 2:**

**NO<sub>x</sub> and N<sub>2</sub>O Control for the Nitric Acid Plant**

The permit indicates that Selective Catalytic Reduction (SCR) will be installed to control N<sub>2</sub>O emissions from the nitric acid plant (page 94 of Appendix B to the Technical Support Document (TSD) and permit Condition D.4.4(b)). However, according to the EPA's December 2010 guidance document titled "Available and Emerging Technologies for the Reduction of Greenhouse Gas Emissions from the Nitric Acid Production Industry," SCR is not an effective control

technology for N<sub>2</sub>O emissions (yielding roughly a 5% reduction in N<sub>2</sub>O). We note that other recent BACT determinations listed in the BACT analysis applied catalytic decomposition to control N<sub>2</sub>O. In addition, the December 2010 EPA guidance document lists Nonselective Catalytic Reduction (NSCR) as an effective N<sub>2</sub>O control option. Based on discussions with your staff, it is our understanding that the statement in the draft permit that SCR has been selected to control N<sub>2</sub>O is not accurate. Please clarify, in the final permit, which BACT control has been selected for reducing N<sub>2</sub>O emissions from the nitric acid plant.

#### IDEM Response

The applicant proposed the use of a combination NO<sub>x</sub> and N<sub>2</sub>O control technology for the nitric acid plant. These are proprietary technologies selected by Midwest Fertilizer Corporation and consist of a single reactor with two operating sections. One section uses a De-NO<sub>x</sub> SCR system where gaseous ammonia is injected and NO<sub>x</sub> is reduced in the presence of a catalyst. The second section of the reactor employs a De-N<sub>2</sub>O tertiary control system where N<sub>2</sub>O is converted to nitrogen and non-hazardous oxides (O<sub>2</sub>, H<sub>2</sub>O, traces of CO<sub>2</sub>) in the presence of a second catalyst. While it is a single reactor unit, there are two distinct processes occurring with different purposes. IDEM, OAQ is updating the BACT and permit to indicate two processes are occurring within the same control unit. NO<sub>x</sub> is controlled by selective catalytic reduction (SCR) and N<sub>2</sub>O is controlled by a catalytic reactor employing reduction/decomposition, tertiary control.

Additionally, IDEM, OAQ is updating the emission unit description for the nitric acid plant to indicate 1,840 metric tons per day of 100% by weight acid equivalent solution will be produced. All permit limits were based on a 100% by weight acid equivalent solution. Finally, Iowa Fertilizer Company updated its GHG BACT for the nitric acid plant and revised the nitric acid production rate to 1,700 metric tons per day in March of 2014. The MFC GHG BACT and NO<sub>x</sub> BACT were updated to reflect the new operating rate. IDEM, OAQ provides additional information on the NO<sub>x</sub> BACT and N<sub>2</sub>O BACT for the nitric acid plant under IDEM's Response to Public Comment No. 26 later in this ATSD.

The following revisions have been made to page 2 of 197 of Appendix B to the Technical Support Document (TSD) because of this comment:

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<b>BACT Review – Subject Units</b>
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- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, **where production is based on 100% by weight acid equivalent solution**, identified as emission unit EU-009, approved for construction in 2014, **NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and is controlled by a Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control**Unit, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

\*\*\*\*\*

The following revisions have been made to page 89 of 197 of Appendix B to the Technical Support Document (TSD) because of this comment:

## BACT Analysis – Nitric Acid Plant (EU-009)

### Emission Unit Description

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, **where production is based on 100% by weight acid equivalent solution**, identified as emission unit EU-009, approved for construction in 2014, **NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and is controlled by a Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control** Unit, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

\*\*\*\*\*

The following revisions have been made to page 92 of 197 of Appendix B to the Technical Support Document (TSD) because of this comment:

### Greenhouse Gas BACT

#### Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for control of greenhouse gas emissions in the nitric acid plant (EU-009):

- (a) — Selective Catalytic Reduction
- (b) — Plant Energy Efficiency Considerations

#### Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ has evaluated the following technologies for use in the nitric acid plant (EU-009):

- (a) — Selective Catalytic Reduction (SCR)  
Selective catalytic reduction (SCR) is a process where a reducing agent is mixed with a waste gas stream in the presence of a catalyst to reduce N<sub>2</sub>O to nitrogen and water. The applicant is using a reactor design with NO<sub>x</sub> and N<sub>2</sub>O emission controls. The use of selective catalytic reduction is a feasible control technology for the nitric acid plant (EU-009).
- (b) — Plant Energy Efficiency Considerations  
Plant energy efficiency considerations include process integration and heat recovery for steam production. The exothermic nature of the reactions means the nitric acid units are net exporters of energy. Therefore, careful consideration should be given to recovering as much of this thermal energy as possible to reduce the overall energy input to the plant. When energy inputs are reduced, greenhouse gas emissions are reduced. The use of plant energy efficiency considerations is a technically feasible control option for the nitric acid plant (EU-009).

#### Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has reviewed the information submitted in support of this BACT determination and has ranked the remaining control options as shown below:

- (a) — Selective Catalytic Reduction (SCR) — 95% control
- (b) — Plant Energy Consideration — Less than 30%.

The applicant intends to install a selective catalytic reduction unit. This is top BACT.

**Step 1: Identify Potential Control Technologies**

The following GHG control technologies apply to the Nitric Acid Unit (EU-009):

- (1) Primary Controls – Suppression of  $N_2O$  formation
- (2) Secondary Controls – Reduction of  $N_2O$  after formation
- (3) Tertiary Controls – Reduction of  $N_2O$  using catalytic control
- (4) Plant Energy Efficiency Considerations

**Step 2: Eliminate Technically Infeasible Options**

- (a) **Primary Controls – Suppression of  $N_2O$  formation**  
Primary controls refer to the modifications made to the catalyst and reaction conditions in the oxidation step to reduce the amount of  $N_2O$  formed. Types of primary controls include extension of the ammonia oxidation reactor. The extended reactor includes an extra chamber free of catalyst between the catalyst and the heat exchangers, allowing additional residence time. Additional primary controls include modification to the oxidation catalyst. The use of primary controls would be considered an inherently lower emitting design. The use of primary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (b) **Secondary Controls – Reduction of  $N_2O$  after formation**  
Secondary control refer to reductions in  $N_2O$  through the use of an additional catalyst, immediately after the oxidation step in the ammonia burner, in which  $N_2O$  is decomposed into nitrogen and oxygen. The use of secondary controls would be an add-on control technology. The use of secondary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (c) **Tertiary Controls – Reduction of  $N_2O$  using catalytic control**  
Tertiary controls refer to reduction in  $N_2O$  through catalytic reduction or decomposition after formation in the oxidation step. The catalyst can be placed either before or after the expander. The two types of catalyst used are non-selective catalytic reduction (NSCR) and catalytic conversion. The NSCR system converts  $N_2O$  with some sort of fuel over a catalyst to produce nitrogen and water. The catalytic conversion process does not require any added fuels or reagents to decompose  $N_2O$  to nitrogen and oxygen. There are several tertiary control systems capable of reducing both  $NO_x$  and  $N_2O$  from waste industrial gases. The Uhde EnviNOx System is one of these patented tertiary control systems. The use of tertiary controls would be capable of producing good results and is technically feasible.
- (d) **Plant Energy Efficiency Considerations**  
Plant energy efficiency considerations include process integration and heat recovery for steam production. The exothermic nature of the reactions means the nitric acid units are net exporters of energy. Therefore, careful consideration should be given to recovering as much of this thermal energy as possible to reduce the overall energy input to the plant. When energy inputs are reduced, greenhouse gas emissions are reduced. The use of plant energy efficiency considerations is a technically feasible control option for the Nitric Acid Unit (EU-009).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**  
IDEM, OAQ has reviewed the information submitted in support of this BACT determination and has ranked the remaining control options as shown below:

- (1) Tertiary Control (98% reduction, vendor guarantee)
- (2) Secondary Control (70% to 90% reduction)
- (3) Primary Control (30% to 85% reduction)
- (4) Plant Efficiency Considerations

A tertiary control system has been selected by the applicant. Therefore, no other analyses are required.

\*\*\*\*\*

The following revisions have been made to page 93 of 197 of Appendix B to the Technical Support Document (TSD) because of this comment:

\*\*\*\*\*

RACT/BACT/LEAR CLEARINGHOUSE DATA Nitric Acid Plants (EU-009) — Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
<del>T129-33576-00059</del>	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.613 lb N <sub>2</sub> O/ton acid, 3 hr. avg.	SCR
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,905 MT/day	N <sub>2</sub> O—30 ppmv, avg. 3 tests; CO <sub>2</sub> e—29,543 ton/12 month rolling; CH <sub>4</sub> —40 ppmv, avg. 3 tests	N <sub>2</sub> O Uhde De-N <sub>2</sub> O System CO <sub>2</sub> e—29,543 ton/12 month rolling; CH <sub>4</sub> —40 ppmv, avg. 3 tests
<del>T147-32322-00062</del>	Ohio Valley Resources	09/25/13	Nitric Acid Plants (EU-001A/B)	630 tons per day, each	1.05 lb N <sub>2</sub> O per ton nitric acid, 3 hr. avg.	Catalytic Decomposition

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Nitric Acid Plants (EU-009) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.613 lb N <sub>2</sub> O/ton acid, 3 hr avg., 100% by weight acid equivalent solution	Tertiary Controls
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,700 MT/day	N <sub>2</sub> O - 30 ppmv, avg. 3 tests; CO <sub>2</sub> e - 44,991 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests	N <sub>2</sub> O Uhde De-N <sub>2</sub> O System CO <sub>2</sub> e - 29,543 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests
T147-32322-00062	Ohio Valley Resources	09/25/13	Nitric Acid Plants (EU-001A/B)	630 tons per day, each	1.05 lb N <sub>2</sub> O per ton nitric acid, 3 hr. avg.	Tertiary Controls

#### RBLC Review

The RBLC contains two entries for nitric acid units in the fertilizer industry. The Iowa Fertilizer Company and Ohio Valley Resources both use a proprietary control technology for N<sub>2</sub>O control. These systems are designed to work with a paired nitric acid reactor. Midwest Fertilizer Corporation is using an ~~SCR system and will achieve N<sub>2</sub>O emissions that are 60% less than the next lowest emission limit.~~ **a tertiary control system using a catalytic reactor to control N<sub>2</sub>O emissions from the Nitric Acid Plant. When all three nitric acid plants are compared on emissions calculated using 100% by weight nitric acid equivalent solution as the production variable, IFC will emit 0.7 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. MFC will emit 0.613 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. OVR will emit 1.05 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. The OVR permit limit applies at all times while the IFC and MFC limits exclude periods of startup, shutdown and malfunction. MFC has proposed the lowest N<sub>2</sub>O emission rate in the RBLC.**

#### Applicant Proposal

The applicant proposed the use of ~~selective catalytic reduction~~ **a catalytic reactor** to achieve a 95% reduction in N<sub>2</sub>O at an emission rate of 0.613 lb N<sub>2</sub>O per ton of **nitric acid** produced, **with the production being expressed as 100 percent nitric acid**, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature. This is top BACT. **The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.**

The applicant provided information as part of the application indicating excess N<sub>2</sub>O emissions during startup and shutdown events from the nitric acid plant are less than two (2) tons per year and IDEM considers these emissions negligible. As such, IDEM, OAQ concurs with the use of work practice standards during startup, shutdown and malfunction (SSM) events. \*\*\*\*\*

The following revisions have been made to page 94 of 197 of Appendix B to the Technical Support Document (TSD) because of this comment:

\*\*\*\*\*

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the nitric acid plant (EU-009) as:

- (a) N<sub>2</sub>O emissions from ~~each of the~~ nitric acid plant (EU-009) shall be controlled at all times by **a catalytic reactor** ~~selective catalytic reduction (SCR)~~, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (b) N<sub>2</sub>O emissions from ~~each of the~~ nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, **with the production being expressed as 100 percent nitric acid**, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) **During periods of startup, shutdown, and malfunction, N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:**
  - (1) **Startup:**  
Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.
  - (2) **Shutdown:**  
Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.



- (3) **Malfunctions:**  
**During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.**

IDEM, OAQ selected an emission limit based on N<sub>2</sub>O instead of CO<sub>2</sub>e because the only GHG reduced by the emission control system is N<sub>2</sub>O. The limit, therefore, requires a high level of performance in reducing the only GHG that can be controlled by the emission control system. N<sub>2</sub>O emissions comprise 95% of the pre-control CO<sub>2</sub>e emitted by the nitric acid stacks. The system does not reduce emissions of any other GHGs. CO<sub>2</sub> is present in nitric acid plant stack: it originates in the compressed air that is used as part of the nitric acid manufacturing process **and a minor amount is generated when natural gas is used for N<sub>2</sub>O conversion.**

Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Nitric Acid Plant (EU-009)
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:

- (1) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton **nitric acid, with the production being expressed as 100 percent nitric acid**, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (2) NO<sub>x</sub> ~~and N<sub>2</sub>O~~ emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (3) **N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a catalytic reactor at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and**
- (43) N<sub>2</sub>O emissions from ~~each of~~ the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, **with the production being expressed as 100 percent nitric acid**, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (5) **During periods of startup, shutdown, and malfunction, NO<sub>x</sub> and N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:**
  - (a) **Startup:**  
**Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas**

turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.

- (b) **Shutdown:**  
Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.
- (c) **Malfunctions:**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

\*\*\*\*\*

The following revisions have been made to Section A.2 – Emission Units and Pollution Control Technology of the PSD/New Source Construction and Part 70 Operating Permit because of this comment:

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: \*\*\*\*\*

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, **where production is based on 100% by weight acid equivalent solution**, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> **and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and is controlled by a Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control** Unit, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

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The following revisions have been made to the emission unit description box in Section D.4 of the PSD/New Source Construction and Part 70 Operating Permit because of this comment:

#### SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

##### Emissions Unit Description:

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, **where production is based on 100% by weight acid equivalent solution**, identified as emission unit EU-009, approved for construction in 2014, **NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and is controlled by a Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control** Unit, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

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

\*\*\*\*\*

The following revisions have been made to the emission unit description box in Section D.4 of the PSD/New Source Construction and Part 70 Operating Permit because of this comment:

#### D.4.4 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:

- (a) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton **nitric acid, with the production being expressed as 100 percent nitric acid**, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (b) NO<sub>x</sub> ~~and N<sub>2</sub>O~~ emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (c) **N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a catalytic reactor at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and**
- (d) N<sub>2</sub>O emissions from ~~each of~~ the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, **with the production being expressed as 100 percent nitric acid**, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (e) **During periods of startup, shutdown, and malfunction, NO<sub>x</sub> and N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:**
  - (1) **Startup:**  
**Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure**

takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.

- (2) **Shutdown:**  
Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.
- (3) **Malfunctions:**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. \*\*\*\*\*

**U.S. EPA Comment No. 3:**

**Greenhouse Gas BACT – CO<sub>2</sub> Purification Process**

The BACT analysis for the CO<sub>2</sub> purification process says that sale of captured CO<sub>2</sub> was evaluated for the entire source and was determined to be not technically feasible because the technology is not available or applicable (page 31 of Appendix B to the TSD). Please include an explanation of how the Indiana Department of Environmental Management reached the conclusion that captured CO<sub>2</sub> cannot be sold.

**IDEM Response**

IDEM, OAQ did not intend to imply captured CO<sub>2</sub> cannot be sold. There are many uses for CO<sub>2</sub> including transportation off-site for use in enhanced oil recovery. In the greenhouse gas (GHG) BACT analysis for the reformer furnace (EU-001), IDEM, OAQ evaluated the cost effectiveness of Carbon Capture and Sequestration (CCS) with construction of a dedicated CO<sub>2</sub> pipeline to a sequestration site. This analysis assumed all of the CO<sub>2</sub> generated onsite was captured, purified and transported to the sequestration site. The analysis determined CCS was not available to Midwest Fertilizer Corporation. As with CCS, the sale of CO<sub>2</sub> is not available to Midwest Fertilizer because existing infrastructure does not exist and construction of a pipeline for a single user is not cost effective. IDEM, OAQ is updating the GHG BACT discussion for the primary reformer and CO<sub>2</sub> purification process to more clearly describe the limitations on the sale of CO<sub>2</sub>. Appendix B to the TSD, page 21 to page 23 of 197 are revised as shown below:

## Greenhouse Gas BACT

### Step 1: Identify Potential Control Technologies

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the reformer furnace (EU-001):

- (a) Carbon Capture and Sequestration (CCS) **and Sale of CO<sub>2</sub>**
- (b) \*\*\*\*\*

### Step 2: Eliminate Technically Infeasible Options

- (a) Carbon Capture and Sequestration (CCS) **and Sale of CO<sub>2</sub>**  
\*\*\*\*\*

## Available Transportation Infrastructure

\*\*\*\*\*

Two other projects in the Rockport, Indiana area have received construction and operation permits from IDEM, OAQ in the past year. One was for Indiana Gasification and the other was for Ohio Valley Resources. The Indiana Gasification project proposed a cross country pipeline to transport liquefied carbon dioxide to the Gulf Coast for use in enhanced oil recovery. This project has been delayed and may not be constructed. A GHG BACT analysis for the Ohio Valley Resource project showed the use of carbon capture and sequestration was not an available option. Rockport, Indiana is approximately 50 miles to the east of Mt. Vernon, Indiana. The business plans of the three facilities are completely independent of each other. The construction of the Midwest Fertilizer Corporation facility will proceed regardless of the construction of the other two facilities.

**As discussed above, CCS is not feasible for Midwest Fertilizer Corporation because it is not available.**

### **Sale of CO<sub>2</sub>**

**The most practical use of captured CO<sub>2</sub> is in the oil and gas industry. CO<sub>2</sub> has been used in enhanced oil recovery for several years.** An economic analysis for ~~these projects~~ **the Ohio Valley Resources project** estimated construction costs **of a CO<sub>2</sub> transmission pipeline** at approximately \$250.00 per linear foot of pipe installed and approximately \$3,450,000 dollars per year in operating costs. Using the same basis, construction costs for ~~this~~ **the Midwest Fertilizer Corporation** pipeline are estimated at \$646,800,000 for a 490 mile pipeline.

\*\*\*\*\*

The capital cost for pipeline construction represents approximately 50% of the construction cost of the entire fertilizer facility. **IDEM, OAQ has determined the sale of CO<sub>2</sub> is not feasible for Midwest Fertilizer Corporation because the pipeline cannot reasonably be constructed and operated by Midwest Fertilizer Corporation.** Carbon capture and sequestration **and sale of CO<sub>2</sub>** ~~are not a~~ technically feasible options for this facility; because, ~~it is~~ **they are** not available or applicable as described above.

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Page 31 of 197 of Appendix B to the Technical Support Document (TSD) has been revised as shown below:

### Greenhouse Gas BACT

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#### Step 2: Eliminate Technologically Infeasible Options

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- (b) Sale of the Captured CO<sub>2</sub>  
Sale of the Captured CO<sub>2</sub> was evaluated for the entire source under the BACT analysis for the reformer furnace. IDEM, OAQ determined **the sale of CO<sub>2</sub> was not feasible** ~~that it was not a technologically feasible option for Midwest Fertilizer Corporation because the technology was not available or applicable.~~ **Midwest Fertilizer Corporation could not reasonably construct and operate a cross county transmission pipeline to an end purchaser of the collected CO<sub>2</sub>.**

- (c) \*\*\*\*\*

#### **U.S. EPA Comment No. 4:**

#### **Startup, Shutdown and Malfunction Emissions**

The NO<sub>x</sub> BACT emission limits for the reformer furnace (permit Condition D.1.4(a)(5)) and the nitric acid plant (permit Condition D.4.4(a)), exclude periods of startup and shutdown. The N<sub>2</sub>O BACT emission limit for the nitric acid plant (permit Condition D.4.4(c)) also excludes periods of startup and shutdown. According to the TSD, potential Startup, Shutdown, and Malfunction (SSM) emissions from this source will be 215.53 tons per year (TPY) of NO<sub>x</sub>, 9.91 TPY of Volatile Organic Compounds, 679.55 TPY of CO<sub>2</sub>, and 214,890 TPY of GHGs. The permit should include a BACT analysis and limits for the SSM emissions from this source. In discussions regarding this draft permit, your staff stated that the SSM emissions from the reformer furnace are controlled by the front end flare (permit Condition D.5). In the final permit, please clarify which SSM emissions are controlled by the front end flare and assure that all SSM emissions are included in a BACT analysis.

#### **IDEM Response**

IDEM, OAQ acknowledges the necessity to address startup, shutdown, and malfunction (SSM) emissions in the BACT analysis and did so in the draft permit documents. The only universally accepted method of control for SSM emissions are measures designed to minimize the occurrence of SSM events and to minimize emissions during these events. As such, IDEM, OAQ addressed SSM control measures by including a flare minimization plan as a BACT condition for each flare. The flare minimization plan includes specific actions for the applicant to follow to minimize emissions specific to each flare. It includes measures to train operators on specific procedures to follow during SSM events. Finally, a condition for a root cause analysis of each malfunction was required to identify causes and preventative measures for each malfunction. IDEM, OAQ also set limits for venting periods to minimize the amount of excess emissions allowable from this source. IDEM, OAQ believes these conditions fully satisfy the requirement to address SSM events in a BACT for units controlled by flares.

The Midwest Fertilizer Corporation facility uses three flares to control emissions during startup, shutdown and malfunction (SSM) events and they are listed in the table below:

<b>Emission Units Controlled by Flares during Startup, Shutdown, and Malfunctions</b>		
<b>Flare</b>	<b>Emission Units Controlled</b>	<b>Emissions during SSM</b>
Front End Flare	Reforming Unit – Reformer Process Purification Unit – Shift Reactor Process Methanation Unit – Methanator Process	NO <sub>x</sub> – 595.49 lb/hr, VOC – 47.26 lb/hr, CO – 3,240.16 lb/hr, CO <sub>2</sub> – 511.81 ton/hr, 336 hr/yr max.
Back End Flare	Ammonia Unit, synthesis gas compressor and its process Ammonia Unit, refrigeration compressor and its process	NO <sub>x</sub> – 624.94 lb/hr, VOC – 11.73 lb/hr, CO – 804.76 lb/hr, CO <sub>2</sub> – 127.12 ton/hr, 336 hr/yr max.
Ammonia Storage Flare	Ammonia Storage Tanks	NO <sub>x</sub> – 125 lb/hr, CO <sub>2</sub> e – negligible, 168 hr/yr max.

Emission limitations for SSM events are limited in the draft permit by setting separate emission limitations during venting events and limiting the total hours of venting allowed per year in each of the flares. Permit Conditions D.5.4(a)(2), (8), (10), (12), and (14) establish SSM limitations for the reforming process including the reformer furnace, shift reactors, and methanator. Permit Conditions D.5.4(b)(2), (8), (10), (12), and (14) establish SSM limitations for the compressors used in the ammonia unit. Permit Conditions D.5.4(c)(2) and (8) establish SSM emission limitations for the ammonia storage tanks.

Potential emissions from each flare are discussed in more detail below:

#### **Front End Process Flare**

There are three sources of emissions during periods of Startup, Shutdown and Malfunction (SSM) associated with the front end processes. The first source of SSM emissions is the reforming unit where feed gas used for ammonia production in the reformer process is flared during SSM. The reforming unit consists of a fired side and a process side. The fired side of the reformer is a heater which combusts natural gas or process gas as a fuel MFC will install a selective catalytic reduction (SCR) unit on the reformer furnace to control NO<sub>x</sub> during steady-state operation. For startup/shutdown where the catalyst bed is below catalyst operational temperature, excess NO<sub>x</sub> emissions will occur. SSM emissions from the fired side are discussed later. On the other hand, the heat released in combustion is absorbed for reforming of natural gas and steam mixture within the reformer. During SSM, the reforming of natural gas is incomplete and products from the reformer can't be used to produce on specification ammonia product. Therefore, this reaction mixture which consists of mainly natural gas, VOC, CO, CO<sub>2</sub>, steam and air is discharged to the flare through pressure control vents. The flare combusts this mixture into the final combustion products listed in the table below.

A second source of SSM emissions is the purification unit where the gas from the shift reactor process is flared during SSM. The shift reactors normally combine carbon monoxide in the exhaust stream of the reformer process with steam to produce hydrogen and carbon dioxide. These units vent until steady state is reached and then the gas is used in the

downstream manufacturing process. The final source of SSM emissions is from the methanation unit where the gas to and from the methanator process is vented to a flare during SSM. Like the shift reactors, the methanator normally does not emit to the atmosphere. The methanator takes the hydrogen rich syngas from the CO<sub>2</sub> purification process and converts any remaining CO<sub>2</sub> and CO back to methane. During startup and shutdown this unit will also vent to the atmosphere. Possible emissions from flare can be summarized in the table below:

Process	Potential SSM Emissions
Reforming Unit	NO <sub>x</sub> , VOC, CO, and CO <sub>2</sub> due to process conditions during SSM and combustion in the flare.
Purification Unit	NO <sub>x</sub> , VOC, CO, and CO <sub>2</sub> due to process conditions during SSM and combustion in the flare.
Methanation Unit	NO <sub>x</sub> , VOC, CO, and CO <sub>2</sub> due to process conditions during SSM and combustion in the flare.

The reforming unit uses reforming catalyst to convert the feed gas & steam to hydrogen, CO and CO<sub>2</sub> at elevated temperatures and pressures. Before reaching these elevated temperatures & pressures, the natural gas has to be vented to operate the various heat recovery coils of the reformer within their design temperature and pressure limits. Therefore, this natural gas needs to be flared during SSM. These temperatures and pressures must be reached gradually for the safety of the process unit and personnel. Startup and shutdown events are infrequent. The reformer will shut down approximately once every two to four years.

In the Purification Unit, the shift reactors take reformer exit gases containing CO and excess steam from the reforming unit, combine it with steam in the presence of a catalyst that operates at a required temperature to create CO<sub>2</sub> and hydrogen. An incomplete reaction at a lower temperature will not convert CO into CO<sub>2</sub>. Therefore the gas mixture will need to be flared during SSM. The required temperature and pressure are gradually reached for the safety of the process unit and personnel.

The methanation unit takes the hydrogen syngas from the purification unit after CO<sub>2</sub> removal and converts any leftover CO or CO<sub>2</sub> to methane and water vapor. This conversion is extremely important for downstream process and is accomplished by the use of a catalyst at elevated temperatures and pressures. During SSM, the pressures and temperatures are not at required levels and the conversion does not reach completion. This gas mixture needs to be flared both from upstream and downstream until proper temperatures and pressures are reached. The required temperature and pressure are gradually reached for the safety of the process unit and personnel. SSM emission estimates are shown below:

Front End Flare Emissions – SSM Emissions			
Pollutant	Emission Limit (mass basis)	Emission Limit (hr/yr)	Potential to Emit (TPY)
NO <sub>x</sub>	595.49 lb/hr	336	100.04
CO	3,240.16 lb/hr		544.35
VOC	47.26 lb/hr		7.94
CO <sub>2</sub>	511.81 ton/hr		171,967



Flare specific SSM minimization procedures for the front end flare include:

- (a) Process syngas streams to flare EU-017 shall not contain ammonia.
- (b) During the sequential startup of the reformer, only one process stream at a time shall be sent to the flare to the extent practicable.
- (c) Maximize the use of process syngas during startup of the ammonia unit.

Mass emissions listed in the table above were from process modeling. A full BACT analysis was performed on the Front End Flare and the results were incorporated into the draft permit under Condition D.5.4(a) including SSM events.

#### Back End Process Flare

There are two sources of SSM emissions from the back end processes and both sources are from synthesis and ammonia compressors and their associated processes. During SSM events, the high pressure sides of each compressor is sent to a flare. Unsteady state emissions consist principally of ammonia from the ammonia compressor and its process and ammonia and synthesis gas from the synthesis compressor and its process. Ammonia is not a regulated pollutant and control is not required by IDEM. IDEM, OAQ treated the back end flare as an emission unit and conducted a complete BACT analysis. IDEM quantified the emissions and provided permit limits to minimize emissions to only those necessary. SSM emission limits are detailed in the table below:

Back End Flare Emissions – SSM Emissions			
Pollutant	Emission Limit (mass basis)	Emission Limit (hr/yr)	Potential to Emit (TPY)
NO <sub>x</sub>	624.94 lb/hr	336	104.99
CO	804.76 lb/hr		135.20
VOC	11.73 lb/hr		1.97
CO <sub>2</sub>	127.12 ton/hr		47,712

Flare use minimization procedures for the back end flare include the following:

- (a) Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable.
- (b) The ammonia compressor main shall be depressurized prior to compressor maintenance.
- (c) The Permittee shall limit venting ammonia rich streams to the flare to the extent practicable during non-emergency startup, shutdown and other flaring events.

Mass emissions listed in the table above were from process modeling. The results of the BACT were incorporated into the draft permit as Condition D.5.4(b), including SSM emissions.

### Ammonia Storage Flare

IDEM, OAQ does not anticipate startup or shutdown emissions from the ammonia storage tanks. These units are atmospheric and cooled to maintain ammonia in a liquid state. Ammonia emissions can occur when the unit vents during upsets or malfunctions. Again, the ammonia flare was provided to prevent odor complaints. IDEM, OAQ treated the ammonia storage flare as an emission unit and conducted a complete BACT analysis. IDEM, OAQ evaluated the startup, shutdown and malfunction emissions from these units and concluded that no controls were feasible. IDEM quantified the emissions and provided permit limits to minimize emissions to only those necessary. SSM emission limits are detailed in the table below:

Ammonia Storage Flare Emissions – SSM Emissions			
Pollutant	Emission Limit (mass basis)	Emission Limit (hr/yr)	Potential to Emit (TPY)
NO <sub>x</sub>	125.00 lb/hr	168	10.5
N <sub>2</sub> O	negligible		Negligible

The results of the BACT were incorporated into the draft permit as Condition D.5.4(c).

### Nitric Acid Plant

In regards to the nitric acid plant, U.S. EPA is correct in indicating SSM emissions were not quantified or included in the draft permit documents but exclusion was provided in the unit's PSD emission limitations for NO<sub>x</sub> and N<sub>2</sub>O for periods of startup, shutdown, and malfunctions. IDEM, OAQ revisited the NO<sub>x</sub> and N<sub>2</sub>O BACT limits for periods of SSM and believes the only practical BACT requirements during SSM events are to minimize the occurrence of SSM events and to minimize emissions during these events. The applicant's emissions estimates indicates excess emissions consist of NO<sub>x</sub> are small and occur infrequently. Planned startup and shutdown events will normally occur two to three times a year. Estimated emissions are presented in the table below:

SSM Emissions from Nitric Acid Plant				
Pollutant	Emission Rate (lb/hr)	Duration (hr/event)	Frequency (events/year)	PTE (TPY)
NO <sub>x</sub>	204.2	3.8	4	1.6

The applicant estimated startup and shutdown at three events per year. IDEM, OAQ added one additional annual event to account for malfunction. SSM emissions for this unit are negligible and NO<sub>x</sub> BACT is work practice standards. IDEM, OAQ addressed SSM BACT work practice standards for N<sub>2</sub>O in IDEM's Response to EPA Comment No. 2. For NO<sub>x</sub>, IDEM, OAQ and the applicant have reviewed operation of the nitric acid plant and have developed the following BACT work practice standards for SSM events:

During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:

- (a) **Startup:**  
Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and  $N_2O$  &  $NO_x$  reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for  $NO_x$  reduction when the control equipment reaches an operating temperature of 600°F.
- (b) **Shutdown:**  
Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.
- (c) **Malfunctions:**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

Finally, IDEM, OAQ clarified the basis of the production term used in the limits set in the BACT determination for the nitric acid plant (EU-009). The applicant will produce a weak 60% by mass nitric acid solution. Compliance with the limit will be determined by converting the actual production mass rate of the solution to a 100% by weight nitric acid equivalent solution basis. This is the same reporting basis as 40 CFR 60, Subpart G reporting for  $NO_x$ .

The nitric acid BACT on pages 91 to 94 of Appendix B to the Technical Support Document have been revised as shown below:

BACT Analysis –Nitric Acid Plant (EU-009)
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\*\*\*\*\*

Applicant Proposal

The applicant proposed the following as BACT:

- (a) \*\*\*\*\*

- (b) NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, **with the production being expressed as 100 percent nitric acid**, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) **The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.**

The applicant has accepted top BACT.

Step 5: Select BACT

IDEM, OAQ has established NO<sub>x</sub> BACT for the nitric acid plants (EU-009) as:

- (a) \*\*\*\*\*
- (b) NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, **with the production being expressed as 100 percent nitric acid**, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.

\*\*\*\*\*

Other revisions required to incorporate this revision to the nitric acid plant NO<sub>x</sub> BACT during SSM events were shown in IDEM's Response to EPA Comment No. 2, above.

**Fired Side of Reformer Furnace**

In regards to the fired side of the reformer furnace, U.S. EPA is correct in indicating SSM emissions were not quantified or included in the draft permit documents but exclusion was provided in the unit's PSD emission limitation for NO<sub>x</sub>. The SCR unit proposed by MFC cannot operate and control NO<sub>x</sub> emissions during SSM events until the catalyst comes up to temperature. The applicant and IDEM reviewed emission estimates during SSM and provide the following NO<sub>x</sub> emission estimate:

**Startup and Shutdown**

**Excess Emission Calculation – Appendix A to the TSD – Page 4 of 30**

Uncontrolled NO <sub>x</sub> emission rate:	133.09 pound NO <sub>x</sub> per hour
Controlled NO <sub>x</sub> emission rate:	10.39 pound NO <sub>x</sub> per hour
Excess emissions during event:	122.70 pound NO <sub>x</sub> per hour

**Event Duration and Estimated Emissions**

Startup Time:	48 hours	NO <sub>x</sub> emissions	2.9 ton
Shutdown Time:	24 hours	NO <sub>x</sub> emissions	1.5 ton
		Emission per Event	4.4 ton

A planned startup occurs approximately every 3 years  
Annual SS emissions 1/3 of single event 1.5 TPY

**Malfunction**

Assume one ton per year 1.0 TPY

**Total Annual SSM Emissions 2.5 TPY**

IDEM, OAQ considers this level of emissions as negligible. Work practice standards to minimize or prevent these events is BACT. The BACT and permit have been revised to include work practice standards for these events.

Page 12 of 197 of the original BACT is revised as follows:

#### **Applicant Proposal**

The applicant proposes the following as BACT:

- (d) \*\*\*\*\*; and
- (e) **Work Practice Standards during SSM.**

#### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for reformer furnace (EU-001) as:

- (a) \*\*\*\*\*
- (c) \*\*\*\*\*; and
- (d) \*\*\*\*\*; and
- (e) **During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:**
  - (1) **Startup:**

Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its “minimum safe stable load” which is defined as that operating condition when:

    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
    - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
  - (2) **Shutdown:**

Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.

- (3) **Malfunction:**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

Page 26 of 197 of the original BACT is revised as shown below:

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Reformer Furnace (EU-001)</b></p>
---

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:

\*\*\*\*\*

- (12) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:
- (a) **Startup:**  
Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its "minimum safe stable load" which is defined as that operating condition when:
- (i) Convection zone parameters fall within ranges recommended by the manufacturer;
  - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
  - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
- (b) **Shutdown:**  
Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.

- (c) **Malfunction**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

Page 39 of 104 of the draft permit is revised as shown below:

D.1.4 Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Limits [326 IAC 2-2-3]

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Pursuant to PSD/Part 70 Operating Permit T129-33576-00059 and 326 IAC 2-2-3 (Prevention of Significant Deterioration), the best available technology (BACT) shall be as follows:

- (a) **Reformer Furnace (EU-001)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:

**General Conditions**

- (1) \*\*\*\*\*

**SSM Events for NO<sub>x</sub>**

- (12) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:

- (a) **Startup:**  
Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its "minimum safe stable load" which is defined as that operating condition when:
- (i) Convection zone parameters fall within ranges recommended by the manufacturer;
  - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
  - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
- (b) **Shutdown:**  
Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.

- (c) **Malfunction:**  
**During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.**

**U.S. EPA Comment No. 5:**

**Hexane Emissions**

Permit Condition D.1.9 limits hexane emissions from the reformer furnace, startup heater, and auxiliary boilers to 9.83 tons per twelve consecutive month period. Compliance with this limit is intended to limit source-wide emissions of a single Hazardous Air Pollutant (HAP) to less than 10 TPY and source-wide total HAP emissions to less than 25 TPY so that the requirements of 326 IAC 2-4.1 do not apply. The permit includes hexane emission calculations in permit Condition D.1.12 based on the fuel usage and an AP-42 emission factor of 1.8 lb/MMCF, or "as determined by testing." However, the permit does not otherwise specify or require testing requirements for hexane emissions. Since the AP-42 emission factor for hexane is rate "E" and the hexane emission limit is 0.17 TPY below the HAPs major source threshold, a testing requirement to determine the accuracy of the emission factor would be appropriate for this source.

**IDEM Response**

IDEM, OAQ does not object to the inclusion of a one-time test to verify the AP-42, emission factor for hexane for the reformer furnace and the auxiliary boilers. Testing of the startup heater is not appropriate because estimated emissions are negligible. Revisions to Condition D.1.10 of the draft permit because of this comment are shown below:

**D.1.10 Testing Requirements [326 IAC 2-7-6(1)] [327 IAC 2-7-6(6)]**

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**Reformer Furnace (EU-001)**

\*\*\*\*\*

- (d) **In order to verify the hexane emission rate (in lb/MMCF of natural gas) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform hexane testing on the reformer furnace (EU-001) stack S-001 utilizing methods as approved by the Commissioner. This is a one-time test. 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.**

\*\*\*\*\*

**Open-Simple Cycle Combustion Turbines (EU-013A and EU-013B)**

(ee) \*\*\*\*\*

(fe) \*\*\*\*\*



(gf) \*\*\*\*\*

(hg) \*\*\*\*\*

Auxiliary Boilers (EU-012A, EU-012B and EU-012C)

(ih) \*\*\*\*\*

(ji) \*\*\*\*\*

(kj) \*\*\*\*\*

- (l) In order to verify the hexane emission rate (in lb/MMCF of natural gas) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform hexane testing on the auxiliary boiler (EU-012A/B/C) stacks S-012A, S-012B, and S-012C utilizing methods as approved by the Commissioner. This is a one-time test. 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.

**U.S. EPA Comment No. 6:**

**HAP Emissions from the CO<sub>2</sub> Purification Vent**

Permit documentation (page 6 of the TSD and page 9 of 10 of Appendix A to the TSD) lists potential HAP emissions from the CO<sub>2</sub> purification process as 8.98 TPY of methanol. Please ensure that the final permit includes the basis for the 0.018594 lb/ton methanol emission factor that is used to calculate potential methanol emissions in Appendix A of the TSD.

**IDEM Response**

IDEM, OAQ does not object to one-time testing of the CO<sub>2</sub> purification process to verify the methanol emission factor used to estimate emissions. Revisions to Condition D.2.6 of the draft permit are shown below:

**D.2.6 Testing Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-6(6)]**

\*\*\*\*\*

- (d) In order to verify the methanol emission rate (in lb/ton of ammonia produced) and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform methanol testing on the CO<sub>2</sub> purification process (EU-003) stack S-003 utilizing methods as approved by the Commissioner. This is a one-time test. 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.

## Public Hearing Comments:

### Public Hearing Comment No. 1

#### John Blair, Valley Watch

My name is John Blair. I'm here representing Valley Watch. Our purpose is to protect the public health and environment of the Lower Ohio River Valley. This certainly qualifies as part of the Ohio River Valley.

I'll keep my comments fairly short. I've -- I'm really disappointed in IDEM's approach to permitting in general, and I think that was proven with the permit that you issued to Ohio -- I think it was Ohio River -- Ohio Valley Resources over in Rockport where we happily challenged that permit before EPA asking them to reject it.

You guys -- in your response to comments, you ignored most of the comments we made. You didn't really act like you even cared. The second thing I want to talk about is the whole issue of toxics and how they impact people's health. Toxic pollution is labeled toxic pollution because it impacts negatively human health, and I've done quite a bit of research actually on UAN plants, ammonia nitrate plants, and other -- other facilities that use processes like this around the country, and what I found is that the large facilities, like this one will be, have an average TRI air emission of ammonia of over eight million pounds a year, and that's in a community that's already inundated with toxic pollution from a variety of sources; the refinery, Sabic, and so forth, and -- 8 million pounds a year.

Rockport is not blessed, but it's kind of like Mt. Vernon in many ways in that it is one of the most toxic polluted places on earth, and Mt. Vernon is one of the most toxic polluted places on earth too, but it can't hold a candle to Rockport, fortunately, as far as the amount of toxic pollutions, but we have -- we have toxic releases in Mt. Vernon that are known carcinogens, almost a million pounds -- let's see -- almost a ton a day, rather, of that. Down from ten tons a day, which I think is admirable that they've been able to cut it that much. But still, I don't know anybody that would like to live next to a ton a day of a known carcinogen being released in the air. And there are people living downwind of this, a lot of people, actually, because of the geography of the area.

The population center really of Posey County has -- is almost in a direct line during many of the summer months when the wind blows from the southwest and goes towards the St. Phillips area, which is probably the center of the concentration of a lot of the population in Posey County due to the -- being a bedroom community, a suburban community of Evansville. So we have a situation where people are already inundated with toxic pollution from A.B. Brown, from Abengoa, from Aventine, from Consolidated Grain & Barge, from the Countrymark Refinery, from Sabic, and now this. And you guys really don't address fugitives,

and I understand why you don't because how can you -- how can you estimate a broken valve or a seal that goes bad or something like that. But you put a great deal of faith in the people that are sponsoring these things that they'll get those seals fixed rapidly, even if it requires shutdown of the process, and I think that's naive. So that's the basis of my comments. Thank you.

### **IDEM Response**

IDEM, OAQ responds to all comments received from interested parties for draft permits subject to the public participation process. Public participation is critical to the permitting process to ensure sources are complying with all of the requirements that apply to them. As part of this process, the public can comment on and request hearings when permits are initially issued, renewed or when major changes to the permits are proposed. The public may also petition the EPA administrator to object to state issued permits, appeal EPA issued permits, and review reports and certifications that permitted sources are required to send to permitting agencies. IDEM, OAQ often combines questions from multiple comments into a single response to prevent the Addendum to the Technical Support Document (ATSD) from becoming repetitive and unnecessarily long. The process of combining comments allows IDEM, OAQ to respond to public concerns while issuing permits in a timely fashion. All comments are important, are treated equally, are answered, and are considered when making a final permitting decision.

Please refer to IDEM Response to Public Comment No. 24, below, for information regarding toxic emissions and human health.

In regards to dangerous releases of toxic materials, Permit Condition C.13 – Risk Management Plan is targeted towards the prevention of accidental releases by implementation of 40 CFR 68 (Chemical Accident Prevention Provisions). Midwest Fertilizer Corporation (MFC) is subject to the requirements of 40 CFR 68 and must prepare a risk management plan. The risk management plan will include the following:

- (1) The accidental release prevention and emergency response policies at MFC;
- (2) A list of regulated substances handled;
- (3) The general accidental release prevention program and chemical-specific prevention steps;
- (4) A five year accident history;
- (5) The emergency response program; and
- (6) Planned changes to improve safety.

The State Chemist, Fertilizer Section regulates the storage and distribution of fertilizer. You may contact the State Chemist at (765) 494-1492 for further information. The State Chemist's website is [http://www.isco.purdue.edu/fertilizer/index\\_fert.htm](http://www.isco.purdue.edu/fertilizer/index_fert.htm).

IDEM, OAQ did address fugitive emissions in preparation of the draft permit. Section D.3 includes requirements for emission unit F-1 (Fugitive Emissions from Equipment Leaks), and Section D.8 contains the requirements for paved roads and parking lots. Paved roads and parking lots are required to be paved, swept daily with a wet suppressant, and all spilled materials are required to be cleaned up in a prompt manner. In addition, a 15 mph speed limit has been established for all haul trucks. To demonstrate compliance, the source is required to achieve a minimum control efficiency of 90% as determined by the method outlined in Condition D.8.5(b). Finally, the source is required to keep daily records of the number of trucks received, the date and time of road dust control treatments and the reason for any deviation. These records allow an IDEM inspector to verify compliance.

In regards to fugitive emissions from equipment leaks, IDEM, OAQ and the applicant estimated the potential fugitive emissions from component leaks on pages 22 to 26, of Appendix A to the Technical Support Document (TSD). These estimates are based on emission factors from Table 2-1, Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017, November 1995. This is a commonly accepted method to estimate fugitive leaks from equipment components.

Finally, MFC is required to institute a Leak Detection and Repair (LDAR) program to control volatile organic compound (VOC) emissions in a manner consistent with 40 CFR 60, Subpart VVa. LDAR requirements were instituted to address VOC emissions from leaking equipment. U.S. EPA suggests leaking equipment, such as valves, pumps, and connectors are the largest source of emissions of VOCs and volatile hazardous air pollutants (VHAPs) from petroleum refineries and chemical manufacturing facilities. LDAR is a work practice intended to identify leaking equipment so emissions can be reduced by prompt repair. All equipment subject to an LDAR program must be inspected at regular intervals to determine if leakage exists. Any component found to be leaking must be repaired or replaced within a specified time period.

The operators at MFC can determine if a valve or seal is leaking by use of optical leak imaging also known as thermography. Optical leak imaging uses an infrared camera to detect and display colorless/invisible VOC emissions as visible emissions on the camera display. Leaks are seen on these instruments as plumes of VOC escaping from the equipment seals and make identification of leaks a simple matter. Emissions are shown in real time and the cameras resemble common camcorders. Further information on optical gas imaging and gas leak detection is readily available on the internet from a number of manufactures.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Hearing Comment No. 2     Ed Adams, Mt. Vernon Redevelopment District**

Thank you for coming here tonight. I just wish we could have done this about six months ago. First of all, I want to put on the record, I drew the short straw. I'm here representing the Mt. Vernon Redevelopment Commission, and we're in full support of this project from the economic standpoint, what this project would mean for the city of Mt. Vernon and Posey County. I think that with what we've done on the riverfront and with what we're getting ready to do on Main Street, this project will draw people to our area, and that's what we're for. So we stand in support of this project. I'm not going to take any more time.

**IDEM Response**

IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Hearing Comment No. 3**

**Mark Beard, Construction Worker Union Representative**

My name is Mark Beard, and I am here representing several thousand construction workers in the building trades from the local area. We're in full support of the project. The feeling is that if this project meets or exceeds all the requirements needed for the air permit, we believe it should be presented to the company so construction can start. We appreciate everything the environmentalists do. We put on the air pollution controls that are mandated. Creates a lot of man hours. So we appreciate it. Thank you very much.

**IDEM Response**

IDEM acknowledges that these comments are important to the commenter. The Office of Air Quality issues air pollution permits to facilities that emit regulated levels of pollutants to the air. Permits require sources to comply with all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board. If an applicant demonstrates that they will be able to comply with all Federal and State laws regarding air pollution, IDEM is required by law to issue the air permit. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Hearing Comment No. 4**

**Steve Wilson**

I just wanted to come up and say that we appreciate IDEM for doing the work that they do, the due diligence of the community. And I appreciate that what Mr. Blair said is in his opinion. A lot of us believe it's different. Being here in the United States with what your organizations do to keep our air clean, unlike China and a number of different countries, is outstanding. So we appreciate your work, and we do support the plant here. Thank you.

**IDEM Response**

IDEM acknowledges that these comments are important to the commenter. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

<b>Public Comments Submitted to IDEM:</b>
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**Public Comment No. 1**

**Application Certification Requirements**

IDEM should verify the Permittee has complied with the certification requirements by a responsible official as specified in 326 IAC 2-7-4(a)(2)(B). It is not clear from the application materials whether MFC submitted a properly certified, complete application for the source that is the subject of the DRAFT Permit. The permit application cover sheet was certified by Michael Chorlton, with a listed title of Authorized Representative. GSD-01 lists Michael Chorlton's title as Consultant & Owner's representative. Based solely on Mr. Chorlton's title, it is unclear whether he meets any of the categories of persons who are qualified to act as a corporation's responsible official in 326 IAC 2-7-1(35)(A)(i) through (vi). IDEM should inquire of the Applicant on what basis Mr. Chorlton qualifies as a responsible official, and determine for which of the six listed categories he qualifies.

IDEM should not issue a permit until it verifies that a responsible official has certified the application.

### **IDEM Response**

IDEM understands the commenter's concern about whether MFC submitted a "properly certified, complete application" to be limited to the issue of whether a qualified "responsible official" of the company certified the application. The commenter is correct that a permit application must be certified as to its truth, accuracy, and completeness by a "responsible official." 326 IAC 2-7-4(f). While IDEM's rules define who may qualify as a "responsible official" for a corporation, the rule leaves open the potential for a "responsible official" to be someone other than a corporation's president, secretary, treasurer or vice president. 326 IAC 2-7-1(35)(A). Specifically, 326 IAC 2-7-1(35)(A)(v) states for "any other person who performs similar policy or decision making functions [as the listed corporate officers] for the corporation" qualifies as a "responsible official." The limitations on individuals who may act as responsible officials is designed to ensure that the person certifying the truth, accuracy, and completeness of an application is in a position of sufficient authority with the applying entity to both (1) evaluate the information being submitted in the permit application and (2) make the appropriate "reasonable inquir[ies]" required for certification. This is supported by EPA guidance which states that, in addition to the named corporate officers in 326 IAC 2-7-1(35)(A), a "responsible official" also could include "persons with the knowledge and authority to assure regulatory compliance." Memo from Lydia Wegman, Deputy Director, U.S. EPA Office of Air Quality Planning and Standards, to Regional Air Directors, U.S. EPA "White Paper for Streamlined Development of Part 70 Permit Applications," 24-25 (Jul. 10, 1995), available at: <http://www.epa.gov/region7/air/title5/t5memos/fnlwtppr.pdf>. IDEM believes that knowledge of an applying entity's proposed operations and authority to control them are necessary elements to a person being properly designated as a "responsible official" under 326 IAC 2-7-1(35)(A)(v).

Based on IDEM's pre-application meetings with MFC, IDEM staff understood that Mr. Chorlton, regardless of title, was the individual making policy decisions for MFC's proposed construction project. IDEM concluded that Mr. Chorlton qualified as a "responsible official" pursuant to 326 IAC 2-7-1(35)(A)(v). Mr. Chorlton does not have the title of President, Secretary, Treasurer, or Vice President of MFC; no individual does. MFC is not, at the time of permitting, organized by these titles and IDEM has no authority to mandate the use of such titles. Corroborating IDEM's acceptance of Mr. Chorlton as a "responsible official" on the permit application, IDEM received the following additional information from MFC in support of Mr. Chorlton's qualifications as a "responsible official" of MFC:

"Mr. Chorlton's title is "Owner's Representative" or "Authorized Representative" when signing contracts for MFC. His responsibilities include among other things: entering into contracts, development and negotiation of sales agreements; establishing the MFC Executive Management Team and overall organizational chart; recruiting the senior managers that will report to the Executive Team; working to finalize the ownership structure; and working on the overall financial closing for MFC. He, also, is responsible for developing the initial environmental, health and safety protocols for the facility."

IDEM is satisfied that Mr. Chorlton qualifies as a "responsible official" pursuant to 326 IAC 2-7-1(35)(A)(v). No changes were made to the permit because of the comment.

### **Public Comment No. 2**

#### **Public Notification Requirements – Increment**

The public notice appearing in the Mt. Vernon Democrat did not contain information concerning the degree of increment consumption expected from the MFC source. The public participation provision in 326 IAC 2-2-15(b)(2) requires that IDEM "[i]nclude information concerning the degree of

increment consumption that is expected from the source or modification with the public notice under 326 IAC 2-1.1-6(a)(2)." (emphasis added). The public notice for the MFC DRAFT Permit that was published in the Mt. Vernon Democrat on January 22, 2014 was silent concerning the degree of increment consumption that is expected from the MFC project. Please clarify whether this was an oversight or whether IDEM considers that the requirement to provide the degree of increment consumption information with the public notice is satisfied by some particular portion of the public notice.

### **IDEM Response**

Registrations, permits, modification approvals, and operating permit revisions issued under Article 2 (Permit Review Rules) are subject to the public notice requirements of 326 IAC 2-1.1-6 (Public Notice). For this PSD/New Source Construction and Part 70 Operating Permit and pursuant to 326 IAC 2-1.1-6(a), the commissioner is required to notify the public of the opportunity to comment on the proposed approval as follows:

- 326 IAC 2-1.1-6(a)(1)(A) The commissioner shall provide notice of the receipt of application to the county executive of a county that is affected by the permit application, the executive of a city that is affected by the permit application, and the executive of a town council of a town affected by the permit application.
- 326 IAC 2-1.1-6(a)(1)(B) The commissioner shall publish a notice requesting comment on the proposed permit approval in a newspaper of general circulation in the area where the source is located.
- 326 IAC 2-1.1-6(a)(1)(C) The commissioner shall provide a document supporting the proposed permit approval for public inspection in the offices of the local air pollution control agency or the local health commissioner.
- 326 IAC 2-1.1-6(a)(1)(D) The commissioner shall allow a period of at least thirty (30) calendar days for public comment.
- 326 IAC 2-1.1-6(a)(2) The commissioner may allow opportunity for a public hearing unless otherwise noted.
- 326 IAC 2-1.1-6(a)(3) The commissioner shall provide notice of the commissioner's issuance to those parties listed in IC 13-15-5-3(c), which includes the permit applicant, each person who submitted written comments, each person who requests notice of the permit determination, and the administrator of the U.S. EPA.

Pursuant to 326 IAC 1.1-6, IDEM, OAQ sent a notice of the receipt of air permit application to the Posey County Commissioners, the Mt. Vernon City Council, and the Mayor's Office of the City of Mt. Vernon on August 27, 2013. A notice requesting comment on the proposed permit approval was published in a newspaper of general circulation, the Mount Vernon Democrat, on January 22, 2014. IDEM, OAQ provided the proposed permit documents to the offices of the local pollution control agency, IDEM's Southwest Regional Office in Petersburg, Indiana. The request for comment published on January 22, 2014, indicated the public notice period ended on March 3, 2014, a period of forty days. Finally, IDEM, OAQ conducted a public hearing on February 26, 2014. All of the requirements applicable prior to issuance of the final

permit were met. If the draft permit is approved, notices will be sent to those parties listed in IC 13-15-5-3(c).

In addition to the requirements of 326 IAC 2-1.1-6, 326 IAC 2-2-15(b) (Public Participation) contains additional requirements for permits subject to 326 IAC 2-2 (Prevention of Significant Deterioration). Pursuant to 326 IAC 2-2-15(b), when making a permit decision under 326 IAC 2-2, the department shall:

- (1) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.
- (2) Include information concerning the degree of increment consumption that is expected from the source or modification with the public notice under 326 IAC 2-1.1-6(a)(2).
- (3) Send a copy of the notice of public comment to the applicant, U.S. EPA, and officials and agencies having knowledge of the location where the proposed construction would occur.
- (4) Consider all written comments submitted within the time specified in the notice of public comment and all comments received at any public hearing or hearings in making the final decision. All comments shall be made available for public inspection in the same locations where the department made available preconstruction information.
- (5) Make a final determination whether construction should be approved, approved with conditions, or disapproved.
- (6) Make the notification of the final determination available for public inspection at the same location where the department made available preconstruction information and public comments relating to the source.

IDEM, OAQ's "notice of public comment" is just one type of "public notice." 326 IAC 2-2-15(b)(2) does not require that IDEM, OAQ include information concerning the degree of increment consumption with the notice of public comment. 326 IAC 2-2-15(b)(2) does not refer to the "notice of public comment." Instead, it refers to the "public notice under 326 IAC 2-1.1-6(a)(2)." 326 IAC 2-1.1-6(a)(2) is the provision that states, "(t)he commissioner may allow opportunity for a public hearing unless otherwise noted." 326 IAC 2-2-15 only refers to the "notice of public comment" in subsections (3) and (4) of the rule, where it states the agencies and persons that the "notice of public comment" shall be sent to and that IDEM, OAQ should consider all comments submitted within the time specified in the "notice of public comment."

In the notice published in the Mt. Vernon Democrat, IDEM, OAQ made a preliminary determination, "IDEM has reviewed this application, and has developed preliminary findings, consisting of a draft permit and several supporting documents, that would allow the applicant to construct the facility." IDEM, OAQ properly included information concerning the degree of increment consumption with the draft permit documents that were placed on public notice. These documents included the Technical Support Document (TSD), which has, as Appendix C, the Air Quality Analysis. The Air Quality Analysis discussed increment consumption in its Section D, on pages 6 through 10.

IDEM, OAQ made available a copy of the draft permit along with the air quality impact analysis with a NAAQS and PSD Increment analysis at the public hearing conducted on February 26, 2014, in accordance with public notice under 326 IAC 2-1.1-6(a)(2), public hearing. In addition, IDEM, OAQ provided the public with the public notice documents at the local library and through an internet link in the public notice published in the local paper.



Finally, a copy of the public notice was sent to a total of twenty-five entities, including the applicant and other interested parties on January 17, 2014, pursuant to 326 IAC 2-2-15(b)(3).

IDEM, OAQ has fulfilled all of its obligations under 326 IAC 2-1.1-6 and 326 IAC 2-2-15(b) for public participation requirements that apply during this period of the permitting process.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### **Public Comment No. 3**

#### **Applicability of 40 CFR 60, Subpart VVa**

Applicability of 40 CFR 60, Subpart VVa requires reconsideration. Although MFC may have demonstrated that it is exempt from 60.482-1a through 60.482-11a, pursuant to 60.480a(c)(3), the reporting requirements in 60.487a remain applicable. Therefore, Condition D.3.6 must be revised to include the 40 CFR 60, Subpart VVa reporting requirements in 60.487a.

The DRAFT Permit (Condition D.3.6) inappropriately establishes 40 CFR 60, Subpart VVa requirements for the UAN Plant and urea ammonium nitrate storage tanks. Affected facilities subject to Subpart VVa are identified in 40 CFR 60.480a. Subpart VVa requires regulated equipment to be within a process unit in the synthetic organic chemicals manufacturing industry. The definitions in 60.481a for both process unit and synthetic organic chemical manufacturing industry require producing, as intermediates or final products, one or more of the chemicals listed in 40 CFR 60.489. While urea is listed in 60.489, urea ammonium nitrate (UAN) is not. Therefore, Subpart VVa applies only to the urea manufacturing; it does not apply to the UAN Plant or the urea ammonium nitrate storage tanks.

It is unclear from either the DRAFT Permit or the TSD whether BACT requires compliance only with the requirements of 40 CFR 60, Subpart VVa that are applicable to the proposed facility based on applicability set forth in Subpart VVa, or whether BACT requires the Permittee to apply the provisions of 40 CFR 60, Subpart VVa as if Subpart VVa applied to the UAN Plant and urea ammonium nitrate storage tanks. If BACT is defined in this latter context, IDEM must clarify how compliance with BACT is to be achieved; it is neither appropriate nor enforceable to specify, for purposes of BACT, compliance with an NSPS requirement (e.g., Subpart VVa) that specifically does not apply, unless the permit includes additional requirements that expand the applicability of NSPS provisions for the purpose of BACT.

### **IDEM Response**

IDEM, OAQ does not always indicate every subparagraph of a rule that applies in regards to NSPS or NESHAP requirements. IDEM, OAQ has in this and previous permits indicated applicable portions based on where the standard makes compliance choices available to the applicant. That is the case with Subpart VVa. IDEM, OAQ does not object to the inclusion of

40 CFR 60.487a in Condition D.3.6. Revisions to the draft permit because of this comment are shown below:

**D.3.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart VVa] [326 IAC 12]**

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- (1) 40 CFR 60.480a(a) to (c);
- (2) 40 CFR 60.480a(d)(1) and (d)(3); ~~and~~
- (3) 40 CFR 60.486a(a)(1), (i), (j), and (k); **and**
- (4) 40 CFR 60.487a.**

Subpart VVa applies to all affected facilities in the synthetic organic chemicals manufacturing industry (SOCMI). MFC is a member of the synthetic organic chemicals manufacturing industry because they manufacture a chemical listed in 40 CFR 60.489, urea, as an intermediate or final product. Urea Ammonium Nitrate (UAN) is not listed in 40 CFR 60.489 and units used in the production of UAN are not subject to this subpart. The commenter is correct in stating the UAN storage tanks are not subject to NSPS Subpart VVa. However, the UAN plant uses a urea solution in the manufacture of 28-32% UAN solution. Therefore, all parts of the process where urea solution is used as an intermediate would be subject to NASP Subpart VVa.

IDEM, OAQ has removed all references of applicability to the NSPS for the Urea Ammonium Nitrate (UAN) storage tanks in the draft permit and Appendix B to the Technical Support Document. Revisions because of this comment are shown below:

Page 4 of 197, Appendix B to the TSD is revised as follows:

\*\*\*\*\*

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa.  
[326 IAC 2-2] ~~[40 CFR 60, Subpart VVa]~~

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Page 193 of 197, Appendix B to the TSD is revised as follows:

<b>BACT Analysis – Urea Ammonium Nitrate Storage Tanks (EU-034, EU-035, and EU-036)</b>
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**Insignificant Activity**

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa.  
[326 IAC 2-2] ~~[40 CFR 60, Subpart VVa]~~

\*\*\*\*\*

Section A.3 of the draft permit is revised as follows:

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): \*\*\*\*\*

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa.  
[326 IAC 2-2] [40 CFR 60, Subpart VVa]\*\*\*\*\*

Section D.3 of the draft permit is revised as shown below:

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

- (e) \*\*\*\*\*

Insignificant Activity:

- (o) \*\*\*\*\*

- ~~(x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa.  
[326 IAC 2-2] [40 CFR 60, Subpart VVa]~~

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

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D.3.5 General Provisions Relating to New Source Performance Standards (NSPS)  
[40 CFR 60, Subpart A] [326 IAC 12-1]

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the urea granulation unit (EU-008), the urea synthesis plant (EU-006), **and** the urea ammonium nitrate plant (EU-007) ~~and the urea ammonium nitrate storage tanks (EU-034, EU-035, and EU-036),~~ except when otherwise specified in 40 CFR 60, Subpart VVa.

D.3.6 New Source Performance Standards (NSPS) [40 CFR 60, Subpart VVa] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR 60, Subpart VVa Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commences after November 7, 2006, included as Attachment D of this permit, which was incorporated by reference as 362 IAC 12, for the urea granulation unit (EU-008), fugitive emissions from equipment leaks (F-1), urea synthesis plant (EU-006), **and the** urea ammonium nitrate plant (EU-007), ~~and the urea ammonium nitrate storage tanks (EU-034, EU-035, and EU-036)~~ as specified as follows: \*\*\*\*\*

#### **Public Comment No. 4**

##### **PSD Minor Limit for SO<sub>2</sub>**

IDEM must reconsider applicable PSD requirements for SO<sub>2</sub> emissions. The DRAFT Permit neither includes synthetic minor SO<sub>2</sub> emission limits nor imposes natural gas fuel quality requirements; therefore, IDEM must either include appropriate conditions in the proposed permit to limit source SO<sub>2</sub> emissions to less than 100 TPY or address the applicable 326 IAC 2-2 requirements.

Review of the application and TSD shows potential SO<sub>2</sub> emissions were calculated using the natural gas SO<sub>2</sub> emission factors in AP-42, Table 1.4-2 (0.6 lb/MMSCF, used for reformer, boilers and flares) and Table 3.1-2a (1.40E-03 lb/MMBtu for natural gas combustion turbines). Use of these factors resulted in uncontrolled SO<sub>2</sub> PTE for the entire source of 7.88 tons/year. The DRAFT Permit limits natural gas consumption from several emission units, resulting in a limited PTE for SO<sub>2</sub> of 7.31 tons/year. These PTE values are small and much less than the PSD SO<sub>2</sub> major source threshold of 100 TPY. Accordingly, neither the Permittee nor IDEM examined the various PSD requirements in 326 IAC 2-2 (e.g., BACT, air quality analysis, increment consumption, etc.) applicable to a new major stationary source of SO<sub>2</sub>, as defined in 326 IAC 2-2-1(ff), prior to DRAFT Permit issuance. As discussed below, the commenter believes this is a significant oversight, and both the permit record and the final permit must be revised to fully address the PSD requirements in 326 IAC 2-2 with respect to SO<sub>2</sub>, or an SO<sub>2</sub> synthetic minor emission limit must be established in the permit.

The DRAFT Permit does not limit SO<sub>2</sub> emissions. As noted in footnotes to the AP-42 tables referenced above, SO<sub>2</sub> emissions from natural gas combustion are based upon all sulfur in the fuel being converted to SO<sub>2</sub>. For the emission factor entry in AP-42, Table 1.4-2, the gas sulfur content is assumed to be 2,000 grains/MMSCF. For stationary combustion turbines, Appendix A to the TSD (Page 16 of 30) uses an emission factor equivalent to burning gas with a sulfur content equivalent to 4.67 grains/MMSCF. This difference in natural gas sulfur content is notable and raises a question regarding the quality of the gas to be burned at the MFC source.

Further, review of 40 CFR 72.2 highlights the differences that may exist in the quality of natural gas burned at a facility. For instance, "pipeline natural gas" is defined to contain sulfur at a concentration of no more than 0.5 grains/100 scf and have a gross caloric value between 950 and 1100 Btu/scf, while "natural gas" is defined to contain sulfur at a concentration of no more than 20.0 grains/100 scf and have a gross caloric value between 950 and 1100 Btu/scf. To be exempted from monitoring fuel sulfur content pursuant to 40 CFR 60.4365(a), which is included in DRAFT Permit Condition D.1.6, the total sulfur content in a current,

valid purchase contract, tariff sheet or transportation contract for natural gas must be no more than 20 grains/100 scf and the natural gas must have potential SO<sub>2</sub> emissions of less than 0.060 lb/MMBtu.

Because what is commonly referred to as "natural gas" may have different fuel sulfur contents, the SO<sub>2</sub> PTE from burning natural gas at the MFC source, unless limited by federally enforceable conditions, may greatly exceed the PSD major source threshold of 100 TPY. For example, if EU-013A-Natural Gas Combustion Turbine were to burn 2,430.47 MMCF/yr natural gas (at 1020 Btu/scf) containing 20 grains/100 scf, as restricted to comply with 40 CFR 60.4365a, the PTE from that unit would be 72.9 TPY SO<sub>2</sub>. Using equivalent quality gas, the EU-001-Natural Gas Reformer burning 8,164.32 MMCF/yr would have a PTE of 245 TPY SO<sub>2</sub>. EU-012A-Auxiliary Boiler 1 limited to burning 1501.91 MMCF/yr would have a PTE of 45 TPY SO<sub>2</sub>. Given the MFC source will have two turbines, one reformer, three auxiliary boilers, and other natural gas combustion sources, the source's SO<sub>2</sub> PTE would exceed 500 TPY, which is over 68 times greater than the 7.31 TPY value evaluated in the DRAFT Permit and TSD, and over 5 times greater than the PSD major source threshold of 100 TPY. Absent enforceable limits that would create a synthetic minor SO<sub>2</sub> source, the PSD requirements in 326 IAC 2-2 are applicable and must be addressed in the MFC permit.

#### **IDEM Response**

The Potential to Emit for sulfur dioxide (SO<sub>2</sub>) was based on the AP-42 emission factor of 0.6 lb/MMCF for the reformer, auxiliary boilers, startup heater and flares and 1.4E-03 lb/MMBtu for the combustion turbines. Both of these factors assume that all of the sulfur (S) in the natural gas is converted to SO<sub>2</sub>. The resulting plant wide emissions estimate of 7.88 tons/year is well below the PSD applicability threshold of 40 tons/year and therefore there are no specific limitations on SO<sub>2</sub> emissions, nor is the facility subject to the PSD requirements. The concern raised by the commenter is whether the sulfur (S) content of the natural gas could be higher than assumed in the AP-42 factors and if so there may be a need to either include an SO<sub>2</sub> limit in the permit or include PSD requirements in the permit for the SO<sub>2</sub> sources.

Midwest Fertilizer Corporation (MFC) has indicated the natural gas supplied to the site will be through a lateral pipeline connected to a Texas Gas Transmission, LLC (TGT) main line. The natural gas supplied by TGT qualifies as "pipeline quality natural gas," which will be used both in the process as well as for fuel in boilers and combustion turbines. Pipeline natural gas has a maximum S content of 0.5 gr/100 scf per 40 CFR Part 72. TGT analyzed samples of the natural gas in its system nearest to the MFC off take location. The results are shown in the table below. The average sulfur content is less than 0.033 gr/100 scf, which is well below the AP-42 assumed value of 0.2 gr/100 SCF (all third party samples with date attached).

Date	Total Sulfur ppm by wt	Grain /100 scf
10-Aug-10	None detected	None detected
21-Feb-12	None detected	None detected
22-Feb-12	<1	<0.033
26-Mar-12	<1	<0.033
30-Jan-13	<1	<0.033
20-Feb-13	1.2	0.040
21-Aug-13	1.3	0.043
26-Nov-13	1.5	0.047
Average	<1	<0.033

Even at this concentration, total SO<sub>2</sub> emissions will be well below the PSD applicability threshold of 40 tons/year. This is illustrated in the following table illustrating various emission levels based on sulfur content.

		PTE of Sulfur Dioxide (SO <sub>2</sub> ) (TPY)		
Emission Unit	Annual Usage (MMCF/year) (See Note)	S = 0.033 gr/100 scf (Local)	S = 0.2 gr/100 scf (AP-42)	S = 0.5 gr/100 scf (40 CFR 72)
Reformer (EU-001)	8,766	0.413	2.502	6.255
Startup Heater (EU-002)	853	0.040	0.243	0.609
Auxiliary Boilers (EU-012A to C)	6,047	0.285	1.726	4.315
Front End Flare (EU-017)	37	0.002	0.011	0.026
Back End Flare (EU-018)	37	0.002	0.011	0.026
Ammonia Storage Flare (EU-016)	14	0.001	0.004	0.010
Combustion Turbines (EU-013A to C)	7,829	0.369	2.235	5.587
Totals	21,963.89	1.11	6.73	16.83
Significant Emission Rate for PSD		40 TPY		

Note: A worst case heating value of 950 MMBtu/MMCF was assumed. This value increases the estimated usage rate from the TSD.

If the natural gas provided to MFC is delivered at the worst-case properties of 0.5 gr S/100 scf and a heating value of 950 MMBtu/MMCF, it is not possible for this source to exceed the PSD significant emission rate of 40 tons per year assuming all of the sulfur in the natural gas is converted to SO<sub>2</sub>. Therefore, an SO<sub>2</sub> BACT analysis is not required. To clarify the definition of natural gas used in IDEM's analysis, Section D.0 was added to the permit to include a definition of natural gas to ensure the total sulfur content of natural gas meets the definition of pipeline natural gas does not exceed 0.5 grains per 100 cubic foot.

The following revisions have been made to the PSD/New Source Construction and Part 70 Operating Permit because of this comment:

## **SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS**

### **Emissions Unit Description:**

#### **Entire Source**

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

### **Definitions**

#### **D.0.1 Definitions**

The terms used in this Part 70 Operating Permit shall have the meanings set forth in the underlying rule or subpart and in this section, whichever is more restrictive, as follows:

- (a) Natural gas-fired means an emission unit fueled by pipeline natural gas.
- (b) Pipeline natural gas has the meaning outlined in 40 CFR 72.2. Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geologic formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot.

#### **Public Comment No. 5**

#### **Desulfurization System Operation**

Safeguards should be included to ensure desulfurization system performance does not result in increased emissions. Sulfur removal is an integral step in proper operation of the proposed process. Sulfur removal also limits the amount of sulfur that may potentially form carbonyl sulfide (a VOC and HAP) under subsequent process conditions. IDEM should consider whether process monitoring is appropriate to ensure sulfur removal system operation does not result in subsequent formation and emissions of hydrogen sulfide or carbonyl sulfide from downstream operations that have not been accounted for or quantified in the TSD. If necessary, appropriate conditions should be included in the permit to ensure poor sulfur removal does not result in increased emissions.

#### **IDEM Response**

Natural gas does contain trace amounts of sulfur compounds. These sulfur compounds if not removed from the pipeline quality feed natural gas would damage the reforming and synthesis catalyst used in the steam methane reforming method of creating nitrogenous fertilizers and are considered as poisons for the catalysts. The sulfur compounds are normally removed by heating the natural gas to between 650 °F and 750 °F and then

hydrogenating the sulfur compounds to hydrogen sulfide ( $H_2S$ ) in a desulfurization vessel. Hydrogen sulfide from the desulfurization vessel is then passed over a zinc oxide catalyst and is converted to zinc sulfide. The zinc sulfide created remains trapped in the catalyst bed and the desulfurized natural gas, containing a non-detectable level of sulfur, is mixed with steam in the reformer for further processing. The spent catalyst is sent off site for regeneration and no emissions are expected from the desulfurization unit.

The applicant proposes the use of a desulfurization unit containing a combination of hydrogenating and zinc oxide beds, which are very effective in removing sulfur compounds from the feed gas.

IDEM has evaluated the possibility of hydrogen sulfide or carbonyl sulfide emissions from this source due to poor performance of the desulfurization unit and following is narrated:

- 1) Any sulfur slipped from desulfurization unit will be trapped by permanent poisoning of downstream catalysts
- 2) The applicant has demonstrated that the sulfur content of natural gas, as given in the IDEM response to Public Comment No.4 above, is very low (i.e. on the average 0.033 gr/100scf). Assuming that all of this sulfur slips from desulfurization unit for one continuous year (practically impossible assumption), the total  $H_2S$  to downstream catalyst will be 0.5 tons.
- 3) Even assuming 0.5 gr/100scf of sulfur in natural gas, as per 40 CFR 72, the  $H_2S$  to the downstream plant will be 7.5 tpy, which will poison the catalyst and will remain trapped.
- 4) As the downstream process conditions are highly oxidizing and all elevated temperatures, with presence of excess steam, formation of carbonyl sulfide is not thermodynamically or kinetically possible.

Based on above, IDEM does not foresee any possibility of  $H_2S$  or COS emissions from this source due to poor performance of desulfurization unit.

Reference EPA Fact Sheet [http://www.epa.gov/chemfact/s\\_carbns.txt](http://www.epa.gov/chemfact/s_carbns.txt), Section III.A, natural gas combustion is not mentioned as a source of carbonyl sulfide emissions. Also in the AP-42, Chapter 1.4 Natural gas combustion, footnote d under table 1.4-2 it is assumed that 100% fuel sulfur is converted to  $SO_2$  therefore the emissions of hydrogen sulfide or carbonyl sulfide from natural gas combustion is not possible.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### **Public Comment No. 6**

#### **Flare Compliance Determination for Particulate**

The Permit must specify how compliance with PM,  $PM_{10}$  and  $PM_{2.5}$  limits is to be determined. Condition D.5.4 requires that the front end flare (EU-017), the back end flare (EU-018), and the ammonia storage flare (EU-016) must comply with PM,  $PM_{10}$ , and  $PM_{2.5}$  limits for flares, based on a "three-hour average". However, Compliance Determination Requirements in Condition D.5.6 and Recordkeeping and Reporting Requirements in Condition D.5.7 are silent on how compliance with the three particulate limits is to be demonstrated and reported. How emissions are to be determined, and how a three-hour average is to be



determined (e.g., how are shutdown periods to be addressed in the calculations, is it a block average, a rolling average, based on at least one data point every 15 minutes, etc.), must be included in the permit.

#### **IDEM Response**

IDEM, OAQ expects PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from each of the flares to be static, and relatively small. PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions will occur because of natural gas combustion in the flare pilot and were calculated using a PTE based on the maximum heat input to the flare pilot and 8,760 hours of operation. There are no additional PM, PM<sub>10</sub>, PM<sub>2.5</sub> emissions anticipated during startup, shutdown or malfunctions. IDEM, OAQ required additional compliance determination requirements for the flares for NO<sub>x</sub>, CO, VOC, and CO<sub>2</sub>, where appropriate, to account for variations in emissions of these pollutants during startup, shutdown and malfunctions.

Compliance with the three-hour average limit is normally determined by averaging the results of three stack test runs, where each test run consists of a one hour sample period. However, open flares do not permit testing. Compliance with the three-hour average limit is accomplished with compliance determination requirements. Compliance determination requirements for each flare are included permit Condition D.5.4(a)(4)(A to C) for the front end flare (EU-017), Condition D.5.4(b)(4)(A to C) for the back end flare (EU-018), and Condition D.5.4(c)(4)(A to C) for the ammonia storage flare (EU-016). Compliance is determined by the use of the following operational practices:

- (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
- (2) Flares shall be operated with a flame present at all times; and
- (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (4) Each flare is required to combust only natural gas for the flare pilot and any purge gas. See Conditions D.5.4(a)(1), D.5.4(b)(1) and D.5.4(c)(1).

Record keeping requirements are a little less unclear. Condition D.5.7(g) attempted to provide a catch all for record keeping required for each flare. To document compliance for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions, the applicant would keep records of all visible emission notations and the output data from the device used to monitor the presence of the flare pilot. These would be considered process operational data. Conditions D.5.7(a), (c), and (e) require records of the type of fuel combusted.

No reporting requirements are required for PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions because they were based on the PTE using uncontrolled AP-42 emission factors and the maximum heat input of the pilot. IDEM OAQ considers the AP-42 emission factors as adequate for estimating the PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions and will not require additional compliance monitoring, compliance determination, recordkeeping, or reporting requirements to verify the PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. NO<sub>x</sub>, CO, VOC, and CO<sub>2</sub> emissions will vary as a function of the number of hours the flares are used to control startup, shutdown and malfunction emissions and will be reported to IDEM quarterly.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment

### Public Comment No. 7

#### Cooling Tower Total Dissolved Solids Readings

The permit should clarify the cooling tower requirements in Condition D.6.7. MFC proposes to construct and operate two cooling towers, one ten-cell tower (EU-010) and one six-cell tower (EU-011). Condition D.6.4 limits total dissolved solids in the water used in each cooling tower to no more than 2,000 mg/l, averaged on a monthly basis. Condition D.6.6 requires recording the level of total dissolved solids in the water used in each cooling tower, at least once per month when each cooling tower is in operation. Water used in cooling towers is typically common to all cells within a particular cooling tower. Condition D.6.7(a) and (b) requires maintaining "...a monthly record of the total dissolved solids concentration in the water used in each cell ..." (emphasis added). The permit should clarify that instead of 16 records (i.e., one for each of the 10 + 6 cells in the two towers), the Permittee is only required to maintain records for the water used in each cooling tower.

#### IDEM Response

IDEM, OAQ does not object to the requested revision. Revisions to the draft permit because of this comment are shown below:

#### D.6.7 Record Keeping Requirements

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- (a) In order to document the compliance status with Condition D.6.4(a)(2), the Permittee shall maintain a monthly record of the total dissolved solids concentration in the water used in ~~each cell of the~~ ten cell cooling tower (EU-010). The Permittee shall include in its monthly record when the total dissolved solids are not recorded and the reason for a lack of a total dissolved solids reading (e.g., the process did not operate that month).
- (b) In order to document the compliance status with Condition D.6.4(b)(2), the Permittee shall maintain a monthly record of the total dissolved solids concentration in the water used in ~~each cell of the~~ six cell cooling tower (EU-011). The Permittee shall include in its monthly record when the total dissolved solids are not recorded and the reason for a lack of a total dissolved solids reading (e.g., the process did not operate that month).

### Public Comment No. 8

#### Methanol Emissions

The DRAFT Permit does not adequately limit methanol emissions. Ammonia manufacture at the proposed MFC source will include a synthesis gas production process. Methanol is a well-documented constituent in emissions from synthesis gas production plants. Accordingly, methanol emissions are an important consideration for permitting construction of the MFC source. If the source's potential to emit for methanol (and every other individual HAP) is less than 10 TPY, and the combined potential to emit of all HAP is less than 25 TPY, the source is an area source for HAP. If either the source's potential to emit for methanol (or any other individual HAP) is 10 TPY or more, or the potential to emit for all HAP is 25 TPY or more, the source is a major source of HAP. When a source becomes a major source of HAP, 40 CFR Part 63 standards become potentially applicable requirements. If a source limits emissions to achieve and maintain area source status (i.e., a permit is issued with enforceable limits to establish PTE at levels

constituting an area source), it must do so before it actually begins to operate; otherwise, once operated with the PTE of a major source, the major source standards become applicable and EPA anti-backsliding policies mandate compliance with applicable major source standards. Should the MFC source trigger HAP major source status, additional requirements would become applicable. Table 1 presents information examining the area source status of the MFC source:

**Table 1- MFC Limited PTE Compared to Major Source Thresholds**

HAP	Uncontrolled PTE of the Entire Source	Limited PTE of the Entire Source (TPY)	Major Source Threshold (TPY)
Hexane	13.21	9.90	10
Methanol	8.98	8.98	10
Total HAP	25.64	23.53	25

From Table 1 and information in the TSD, it can be seen that limiting annual natural gas combustion is effective in limiting potential hexane emissions; however, limiting natural gas combustion does not directly limit methanol emissions. Table 1 shows that a relatively small increase in methanol emissions (only 1.02 TPY, to 10 TPY) would define the MFC source as a 40 CFR Part 63 major source. Neither the MFC application nor the TSD provides sufficient process design information to allow an assessment of whether the MFC source will actually operate with methanol emissions less than 10 TPY. Examination of public information available for methanol emissions from facilities producing synthesis gas, and other technical documents, indicates methanol emissions from the MFC process, absent some unique design specifications setting its design apart from other designs, may likely exceed 10 TPY. Table 2, below, shows why potentially higher emissions are a concern (i.e., the MFC methanol emissions factor is significantly less than the other references). Therefore, if the MFC source desires to be an area source, its permit must include enforceable restrictions limiting methanol emissions in the MFC permit to less than 10 TPY.

**Table 2 - Methanol Emission Factors for Ammonia Syngas Production**

Reference	Methanol emission factor	TPY Methanol for MFC-scale plant	Methanol Major Source Threshold
AP-42 Table 8.1-1	1.2 lb/ton	579	10
Ohio Valley Resources (OVR) permit	0.1863 lb/ton 0.1831 lb/ton 0.0352 lb/ton	90 88 17	10
US Patent 6015450A conventional conditioning unit example	0.6280 lb/ton	303	10
US Patent 6015450A present invention example	0.0419 lb/ton	20.2	10
MFC Draft Permit TSD	0.018594 lb/ton	8.98	10

Having worked with chemical process technologies in the chemical industry for 40 years, the Commenter understands that selection, and proper operation, of process technology can considerably impact process emissions. US patent 6015450A (Reducing methanol emissions from a syngas unit), referenced in Table 2, provides an illustrative example. The patent describes how methanol emissions in the CO<sub>2</sub> vent from a synthesis gas unit in an ammonia or hydrogen plant are reduced by contacting raw synthesis gas from a low-temperature shift converter with recycled stripped condensate to absorb methanol. This demonstrates that good chemical engineering and operational control can significantly impact methanol emissions. It also demonstrates that variation in design and operation can result in increased emissions.

As shown in Table 2, the methanol emission factor included in the MFC application is substantially less than methanol emission factors derived from other references. Should operation of the MFC process cause methanol emissions to shift toward the higher emissions reported or estimated for other ammonia plants, it would not take much variation to

cause the methanol emissions to exceed the major source threshold. Further, the CO<sub>2</sub> Vent Emissions (EU-003) is identified as emitting 8.98 TPY methanol. Accordingly, the MFC area source status is highly dependent upon presumed emissions from just one process vent.

The TSD only briefly discusses methanol emissions. IDEM should more fully explain the nature of the engineering estimates, whether there are critical process design and operational parameters that must be achieved to limit methanol emissions to the levels upon which permit determinations have been made, in what ways the catalyst affects methanol emissions, whether there are additional methanol emissions resulting from condensate being recycled from downstream of the low-temperature shift reaction, whether there are additional methanol emissions associated with process startup, and whether other streams following the outlet of the low-temperature shift reactor contribute any methanol emissions that have not been accounted for in the TSD emission summary.

Absent sufficient supporting information to the contrary, it is not unreasonable to consider that methanol emissions may cause the MFC source to be a major source for HAP. Therefore, IDEM should expressly limit source methanol emissions to less than 10 TPY and require sufficient compliance demonstration, monitoring, record keeping and reporting to ensure methanol emissions do not exceed 10 TPY. If the methanol PTE is not affirmatively limited to less than 10 TPY, IDEM must revise the DRAFT Permit and issue a permit that includes 40 CFR Part 63 standards that are applicable to a major source. IDEM should clearly document its considerations, and the process design and operation parameters it determines are necessary to achieve the methanol emissions rate of less than 10 TPY upon which area source DRAFT Permit conditions are predicated.

#### **IDEM Response**

IDEM, OAQ added a testing condition for methanol. Please see IDEM's response to EPA Comment No. 6.

#### **Public Comment No. 9**

##### **Methanol Testing Requirements**

Testing should be required to establish an "as-constructed" emission factor for methanol. Condition D.2.6(b) requires VOC testing for the CO<sub>2</sub> purification process for the purpose of demonstrating compliance with the PSD BACT VOC limit in D.2.4(c). Use of a test method that specifically quantifies methanol when determining VOC would demonstrate the source's status as a major or area source for methanol (HAP). While IDEM permits would not typically include a methanol testing requirement in a condition intended to demonstrate VOC compliance with a PSD BACT requirement, including methanol determination in another permit condition for the purpose of demonstrating source HAP status is necessary.

### **IDEM Response**

IDEM, OAQ added a testing condition for methanol. Please see IDEM's response to EPA Comment No. 6.

### **Public Comment No. 10**

#### **Underlying Requirements for Flare Record Keeping**

The Permit must specify determination and recordkeeping for data used to determine compliance with flare limitations.

Condition D.5.7(g) provides: In order to document compliance status with Conditions D.5.4(a)(2), D.5.4(b)(2), and D.5.4(c)(2), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.

Conditions D.5.4(a)(2), D.5.4(b)(2), and D.5.4(c)(2) impose hours of operation limits; however, emission limits are set forth in other sub-conditions in those three conditions (e.g., D.5.4(a)(5)-(14), D.5.4(b)(5)-(14), and D.5.4(c)(5)-(11)). Thus, the references to the three conditions in Condition D.5.7(g) are too narrow. Condition D.5.7(g) should be revised, as follows, to require keeping records used to determine flare emissions (deleted text is struck through):

In order to document compliance status with Conditions D.5.4(a)(~~2~~), D.5.4(b)(~~2~~), and D.5.4(c)(~~2~~), the Permittee shall maintain records of flow monitoring data, process operational data, mass balance, or other engineering estimation methods used to determine flare emissions.

### **IDEM Response**

The intent of Condition D.5.7(g) was to require the applicant to maintain the records needed to calculate PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions. Condition D.5.7(g) should cover any condition where a measurement or estimate is made to justify the sources estimate of emissions. For each flare, the applicant will measure hours of venting, will continuously monitor the presence of the pilot flame, and will measure gas flow rates. Conditions D.5.4(a)(2), (b)(2), and (c)(2) require the applicant to maintain records of the hours of venting. Condition C.17(a) requires the applicant to maintain records of continuous monitoring equipment instrumentation. The expansion of conditions recommended by the applicant is outside of the intent of the condition. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### **Public Comment No. 11**

#### **Definition of PM<sub>2.5</sub>**

The DRAFT Permit and TSD have numerous usages of PM<sub>2.5</sub>. Some is in discussion and some pertains to a limitation or other regulatory requirement.

326 IAC 1-2-52.2 states: "PM<sub>2.5</sub>" means particulate matter with an aerodynamic diameter less than or equal to a nominal two and five-tenths (2.5) micrometers (µm).

326 IAC 2-1.1-1(2) states: "Direct PM<sub>2.5</sub>" means solid particles emitted directly from an air emissions source or activity, or gaseous emissions or liquid droplets from an air

emissions source or activity that condense to form PM<sub>2.5</sub> at ambient temperatures. Direct PM<sub>2.5</sub> emissions include elemental carbon, directly emitted organic carbon, directly emitted sulfate, directly emitted nitrate, and other inorganic particles, including, but not limited to, crustal material, metals, and sea salt.

For purposes of PSD, 326 IAC 2-2-1((ww)(1)(F) defines “significant” in terms of ten (10) tons per year direct PM<sub>2.5</sub>.

Accordingly, for permits that have underlying determinations or requirements in terms of either or both of PM<sub>2.5</sub> or direct PM<sub>2.5</sub>, the intended usage of PM<sub>2.5</sub> can be unclear. Because compliance depends upon using appropriate compliance determination methods, IDEM should discuss differences and clarify the pollutant (i.e., PM<sub>2.5</sub> or direct PM<sub>2.5</sub>) for which compliance is to be determined.

#### **IDEM Response**

IDEM, OAQ intended to reference direct PM<sub>2.5</sub> in its permitting analysis of PM<sub>2.5</sub> for PSD. The commenter is referred to page 2 of 53 of Appendix A to the Technical Support Document (TSD) where PM<sub>2.5</sub> in terms of the County Attainment Status was discussed. Paragraph (b) of this section states:

- (b) **PM<sub>2.5</sub>**  
Posey County has been classified as attainment for PM<sub>2.5</sub>. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for PM<sub>2.5</sub> 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<sub>2.5</sub> significant level at ten (10) tons per year. This rule became effective June 28, 2011. Therefore, direct PM<sub>2.5</sub>, SO<sub>2</sub> and NO<sub>x</sub> emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

In addition, the potential to emit of the entire source after issuance table on page 7 of 53 of Appendix A to the Technical Support Document (TSD) clearly indicates PM<sub>2.5</sub> emissions were reviewed as direct PM<sub>2.5</sub> emissions. For the purposes of PSD, IDEM, OAQ used direct PM<sub>2.5</sub> in its analysis. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### **Public Comment No. 12**

##### **Greenhouse Gas Emission Limitations as CO<sub>2</sub>e**

326 IAC 2-2-1(zz) establishes that determination of pollutant greenhouse gases (GHGs) includes more than carbon dioxide. When calculated pursuant to paragraph (zz), the amount of GHGs is expressed as CO<sub>2</sub> equivalent emissions (CO<sub>2</sub>e). Permit limitations established pursuant to the PSD rules must be in terms of CO<sub>2</sub>e. When issued, the permit's GHGs limits need to be changed to limit CO<sub>2</sub>e, not just CO<sub>2</sub>. See, e.g., D.1.4(a)(10) and (11), D.1.4(b)(8), D.1.4(c)(10) and (11), D.1.4(d)(10), D.2.4(d) and (e), D.5.4(a)(13) and (14).

### **IDEM Response**

IDEM, OAQ focused its analysis on CO<sub>2</sub> in the greenhouse gas (GHG) BACT for the reformer furnace, startup heater, gas turbines, auxiliary boilers, and flares. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

IDEM, OAQ focused its analysis on CO<sub>2</sub> in the greenhouse gas (GHG) BACT for the CO<sub>2</sub> purification process. While other GHGs, such as methane or N<sub>2</sub>O may be present in trace amounts, emissions will be in excess of 99% CO<sub>2</sub>. The trace amounts of methane and N<sub>2</sub>O in the near pure stream of CO<sub>2</sub> cannot be controlled by combustion devices because of the low heat content of the gas stream. Unreasonably, large amounts of makeup combustion fuel would have to be added to control the trace amounts of methane and N<sub>2</sub>O. Outside of combustion, there are no known add-on control measures for these pollutants. To the extent measures are identified that reduce 100% venting and thereby CO<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### **Public Comment No. 13**

#### **Fuel Specifications for Natural Gas Fired Units**

Some combustion units are intended to combust only natural gas, while others may combust natural gas and/or process off-gas. The permit should specify that combustion units not being permitted to also combust process off-gas shall combust "only" natural gas. Such a clarification would reflect the basis of the application and TSD, and ensure emissions are those derived only from natural gas combustion. As an example of the suggested change, Condition D.1.4(c)(2) would be revised to read (added text is in underlined and bold font):

The natural-gas fired open-cycle combustion turbines with heat recovery (EU-013A/B) shall combust **only** natural gas;

### **IDEM Response**

IDEM, OAQ clearly identified all combustion fuels in its emission unit descriptions. Where the phrase "natural gas-fired" is used, the emission unit is authorized to combust only natural gas. Where the phrase "combusting a combination of" is used, the emission unit may combust more than one fuel as specified in the description. The reformer furnace is the only emission unit authorized to combust two fuels, process gas and natural gas. Where the phrase "distillate oil-fired" is used, the emission unit is authorized to combust only distillate oil (No. 2 fuel Oil).

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.



#### **Public Comment No. 14**

#### **VE Notations for Urea Granulator**

The Urea Granulator Unit (EU-008) is a large emitter of controlled particulate emissions (PM, PM<sub>10</sub>, and PM<sub>2.5</sub>). It is controlled by a wet scrubber. This unit's uncontrolled PTE is 472.09 TPY, and controlled PTE is 47.21 TPY. As such, it represents nearly half of the permitted PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions for the source.

Condition D.3.10 requires parametric monitoring for the wet scrubber. Because the scrubber has such large potential emissions, the permit should also require periodic (e.g., weekly) visual emission notations (VEN) to determine whether emissions are abnormal. An abnormal emission may possibly occur even while the scrubber pressure drop parametric monitoring is in the defined normal range. Records of the VEN should be recorded and maintained. An abnormal VEN should not be a deviation, but should trigger further response in accordance with Section C – Response to Excursions and Exceedances. Inclusion of VEN requirements would potentially minimize ongoing abnormal emissions should the wet scrubber not provide its normal control while operating within its normal parametric range.

#### **IDEM Response**

The urea granulator unit (EU-008) does have a large potential to emit of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> and compliance determination and compliance monitoring requirements are necessary. The draft permit requires an initial and reoccurring stack testing for PM, PM<sub>10</sub> and PM<sub>2.5</sub> and requires the use of the scrubber at all times as compliance determination measures. During the stack test, the emission rates proposed in the draft permit will be verified along with the scrubber pressure drop measured during the compliant stack test. The scrubber pressure drop monitoring is used between stack tests to assure compliance with the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emission limits on a continuous basis. The operator must make a pressure drop reading once per day, record the pressure drop in a log, and the log must be available to IDEM during an inspection. Midwest Fertilizer and IDEM, OAQ both agree that scrubber pressure drop monitoring is adequate to assure compliance with the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emission limits on a continuous basis.

Other alternative measures for parametric monitoring considered during the review of this application include liquid flow rate and visible emission notations. Liquid flow rate and VE notations are both effective in determining continuous compliance with emission limitations and are often selected by sources. For liquid flow rate monitoring, the operator would make a flow rate reading once per day, record the flow rate in a log, and the log would be made available to IDEM during an inspection.

For visible emission notations, the operator would determine if emissions look normal or abnormal. This is effective for a properly trained operator but requires some judgment. For visible emission notations, the operator would make a VE reading once per day, record the VE in a log, and the log would be made available to IDEM during an inspection.

IDEM, OAQ is confident continuous compliance can be demonstrated by the use of the scrubber at all times, along with daily pressure drop readings and repeat stack testing. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

## Public Comment No. 15

### Urea Granulator BACT

A BACT analysis for the Urea Granulator (EU-008) is provided in the TSD. Review of the Uncontrolled PTE and the Limited PTE shows control of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> is based upon 90 percent control efficiency. While the BACT analysis references "Wet Scrubber 90% Control" for BACT, the analysis does not sufficiently justify the reasons why 90% control is an appropriate BACT determination for the MFC Urea Granulator. The TSD references the RACT/BACT Clearinghouse Data for Koch Nitrogen Company (wet scrubber 90% control) and then dismisses the Koch Nitrogen Company limitation of 6.6 lb/hr PM<sub>10</sub> because a stack test indicated higher emissions.

The TSD briefly discusses the operation of the Urea Granulator, including the coating of fine particles to form larger particles, that urea particles are sticky and hygroscopic, and that the physical properties make wet scrubbers an ideal control device. Yet, BACT is based on only 90% control, without explaining why higher control is not achievable with available control equipment.

Wet scrubber performance is dependent, among other considerations, upon the scrubber design selected (i.e., hi-efficiency, med-efficiency, or low-efficiency), the particle size distribution in the stream to be controlled, and whether demisters are installed at the scrubber outlet. AP-42, Table B.2-3 provides typical control efficiencies for wet scrubbers, with hi-efficiency wet scrubbers achieving 90% control for 0-2.5 micron particles, 95% for 2.5-6 micron particles, and 99% for 6-10 micron particles. An EPA test report for a urea granulation scrubber documents 99.8% control efficiency. Nevertheless, the TSD and DRAFT Permit apply 90% uniformly to all three particulate pollutants (i.e., PM, PM<sub>10</sub>, and PM<sub>2.5</sub>), without any discussion of the particle size distribution for the MFC wet scrubber inlet. Given the hygroscopic nature of urea, the ideal nature of a wet scrubber for urea control, and reported high efficiency for wet scrubber designs, the TSD has not demonstrated that BACT for the MFC Urea Granulator is only 90% control. If a large quantity (by mass) of material entering the wet scrubber is greater than 6 micron size, then BACT would likely be much greater than 90% (for a hi-efficiency scrubber). If MFC is not proposing a hi-efficiency scrubber, or a hi-efficiency scrubber with a demister on the wet scrubber outlet, then the BACT analysis must justify why such a less efficient scrubber design constitutes BACT. If BACT reconsideration establishes lower emission limits, the permit must be appropriately revised.

### IDEM Response

The emission unit description for the urea granulator indicates particulate emissions are controlled by a high efficiency wet scrubber. Section A.2(e) of the draft permit provides the following description:

- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]

The commenter is correct in stating the BACT requires a wet scrubber to be in operation at all times and not a "high efficiency" wet scrubber. In this case, the numerical removal efficiency is not important because IDEM, OAQ established a BACT limit based on emissions of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> per ton of product produced. This is a more illustrative measure of particulate removal efficiency when viewed over multiple manufactures and permits. It is possible for a granulator to have a higher removal percentage but higher actual emissions. While similar, not all processes are identical and some may create higher levels of uncontrolled particulate. Say one unit produced 1,000 tons of uncontrolled particulate to produce 1,000 tons of granular urea while another only produced 900 tons of uncontrolled particulate to produce 1,000 tons of granular urea. One unit would be allowed to emit 100 tons of particulate while the other would be allowed to emit 90 tons, assuming both are 90% efficient. An emission limit based on pounds emitted per ton of product produced would be identical. An emission limit based on 90% control and 900 tons of uncontrolled emissions per 1,000 tons of product gives us a 180 lb/ton emission limit. For the dirtier process, an emission limit of 180 lb/ton requires the wet scrubber to achieve a 91% removal efficiency. The pound emission per ton of product is the best method to limit the urea granulator.

In determining BACT, IDEM, OAQ determined the only viable control technology was a wet scrubber. All of the RBLC entries controlled emissions with a wet scrubber. IDEM, OAQ's next task was to determine the lowest emission rate achieved in practice. IDEM, OAQ researched the permit limits proposed by Koch Nitrogen and determined the actual emission rate proposed was higher than the limit proposed by MFC. Koch nitrogen has three granulators each allowed to emit at 6.6 pounds per hour to produce 517 tons per day urea, for a total emission rate of 19.8 pounds per hour to produce 1,550 tons per day of granular urea. This equates to an emission rate of 0.3 pounds of particulate per ton of granular urea produced. MFC proposes an emission rate of 0.164 pounds per ton. MFC has a much stricter emission limitation. Once again, the best method to compare multiple units is by a production based limit and not control efficiency.

With respect to the proposed PM<sub>2.5</sub> limit which is the same as the PM<sub>10</sub> and PM limit we have again reviewed other similar permits. While the Iowa Fertilizer permit (issued by the Iowa DNR) does have a lower PM<sub>2.5</sub> limit, the Iowa DNR's more recent permit for the CF Industries Nitrogen facility's granulator unit has limits which are the same for PM, PM<sub>10</sub> and PM<sub>2.5</sub>. We also continue to question whether there is sufficient technical justification in the Iowa Fertilizer permit to justify establishing a lower PM<sub>2.5</sub> limit. It is more difficult to remove finer particles vs. coarser ones and we find it technically questionable to use a limit for PM<sub>2.5</sub> which is significantly lower than that for PM or PM<sub>10</sub>.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### **Public Comment No. 16**

#### **Ammonia Emissions are not Protective of Human Health**

The TSD has failed to establish that the permit is protective of public health with respect to ammonia emissions from the proposed MFC source. Ammonia is not an air pollutant subject to regulation for purposes of the PSD regulations in 326 IAC 2-2; additionally, ammonia is not a pollutant that triggers permitting under the provisions of 326 IAC 2-7-10.5. Perhaps these are the reasons that the permit application, TSD, and DRAFT Permit do not address the ammonia emissions from the proposed source.

Nevertheless, 326 2-1.1-5(5) imposes upon IDEM an independent requirement that prohibits issuance of a permit that is not protective of public health. Operations of the type proposed by MFC are known to have substantial ammonia emissions. Without quantifying the level of potential ammonia emissions from the proposed source and providing an objective assessment of their impact, it is not possible to determine whether such ammonia emissions are at a level protective of public health. Before issuing the permit, IDEM must determine that ammonia emissions from the permitted source will not be detrimental to public health.

### **IDEM Response**

IDEM, Office of Air Quality (OAQ) understands the concerns of the commenter.

IDEM, OAQ has no authority to regulate ammonia under 326 IAC 2-2 (PSD). Ammonia is not a VOC or HAP or otherwise listed as a regulated air pollutant under PSD. IDEM, OAQ has no information regarding ammonia emissions from Midwest Fertilizer Corporation. General information regarding ammonia can be located at <http://www.epa.gov/iris/subst/0422.htm> on the U.S. EPA website.

326 IAC 2-1.1-5 (Air Quality Requirements) does indeed prohibit the commissioner from issuing a preconstruction approval to any person for construction or modification of any source or emission unit if the commissioner determines that the terms and conditions of the preconstruction approval are not protective of the public health.

The general provisions at 326 IAC 2-1.1 provide a road map for specific air permitting requirements located in other rules in Article 2 for construction of sources. The basis for the requirements in 326 IAC 2-1.1-5 are from IDEM's original air permit construction rules that were approved into Indiana's state implementation plan (SIP). Statutes and regulations should not be construed as stand-alone provisions, independent of the context created by the statutes or regulations in which they are grouped. *Fuller v. State*, 752 N.E.2d 235, 238 (Ind. Ct. App. 2001) ("Statutes relating to the same general subject matter are *in pari material* and should be construed together so as to produce a harmonious statutory scheme."); *Centre Properties v. DNR, In re Hoosier Environmental Council*, 10 CADDNAR 49 (March 24, 2005); see also *Miller Brewing Co. v. Bartholomew County Beverage Cos., Inc.*, 674 N.E.2d 193 (Ind. Ct. App. 1996) (canons of construction apply in the same manner to both statutes and rules.). Accordingly, 326 IAC 2-1.1-5 cannot be read in isolation from the other applicable IDEM permitting rules.

Most importantly, 326 IAC 2-1.1-5's application is limited by 326 IAC 2-1.1-2, which states:

"(a) This rule [326 IAC 2-1.1 *et seq.*] applies to the issuance of a registration, permit, modification approval, or operating permit revision required under this article [326 IAC Article 2] and the sources or emissions units required to obtain a registration, permit, modification approval, or operating permit revision under this article, **except where rules in this article establish more specific requirements.**" (**emphasis added**).

Title 326 of the Indiana Administrative Code, and most relevant here, the Prevention of Significant Deterioration (PSD) rule in 326 IAC 2-2, sets out the specific air pollutants that IDEM, OAQ may regulate. As the commenter noted, ammonia is not an air pollutant subject to regulation in a permit for preconstruction approval. Ammonia is not included in the definition of "regulated NSR pollutant" in 326 IAC 2-2-1(ss). This specific rule defining the

pollutants to be regulated would be meaningless if IDEM were to use the general requirement of 326 IAC 2-1.1-5 to regulate additional pollutants, such as ammonia.

The Office of Air Quality (OAQ) issues air pollution control permits to facilities that have the potential to emit regulated levels of pollutants into the air. Permits require sources to comply with all health-based and technology-based standards established by the U.S. EPA and the Indiana Air Pollution Control Board. Before the draft permit is made available to the public for review, a great deal of effort is made by IDEM, OAQ to ensure that the permit contains all applicable federal and state air pollution regulations and the source is issued the correct permit level based on its potential to emit, and that the correct controls, monitoring, and reporting requirements are included in the permit to ensure that the source will be in compliance with these requirements contained in the permit. If an applicant demonstrates that it will be able to comply with all applicable federal and state laws regarding air pollution, IDEM is required by law to issue the permit.

Air emissions from sources are regulated because high levels of emissions can cause severe health effects, chronic health effects and death. 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 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. Detailed information about the health effects of these pollutants is available at <http://www.epa.gov/air/urbanair/>. The complete table of the NAAQS can be found at <http://www.epa.gov/air/criteria.html> on the Internet. Posey County is in attainment for all criteria pollutants.

The source's air emissions will also include some Hazardous Air Pollutants (HAPs). More information about these pollutants is available at <http://www.epa.gov/air/airpollutants.html> on U.S. EPA's website.

IDEM has drafted the air permit to limit the amount of emissions to the very lowest level allowed by law. In addition, IDEM, OAQ performed air dispersion modeling in Posey County, Indiana to ensure the proposed facility did not pose a threat to public health or the environment. IDEM, OAQ's analysis showed the proposed facility will not significantly impact the ambient air quality in Posey County, Indiana and a significant increase in asthma or cancer is not expected. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required as a result of this comment.

**Public Comment No. 17**

**Incorrect Rule Citation in 326 IAC 2-2-15(b)(2)**

The reference to 326 IAC 2-1.1-6(a)(2) in 326 IAC 2-2-15(b)(2) should be reviewed. It seems the reference should be to the public notice provision in 326 IAC 2-1.1-6(a)(1)(B). Please ask IDEM's rule revision staff to review the reference when considering future rule updates.

**IDEM Response**

The rule citation referenced by the applicant is correct. As discussed in IDEM's Response to Public Comment No. 2, increment consumption is described in Section D of the Air Quality Analysis, which is Appendix C to the Technical Support Document. It is also part of the public hearing process. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### **Public Comment No. 18**

#### **Comments of John Blair, Valley Watch**

First, Valley Watch wishes to acknowledge and endorse the extensive technical comments we understand are being filed by Mr. David Boggs of Mt. Vernon, IN. Secondly, it should be clear that the comments filed on behalf of Valley Watch by our Board Member, Mark Bryant are indeed, part of the record of comments being filed by Valley Watch.

And last, we reiterate our continuing concerns for the huge levels of toxic chemical releases from existing sources in and around Mt. Vernon and southern Posey County, IN, which make additional toxic releases from this facility an even greater hazard for human beings downwind of Midwest Fertilizer's proposed facility.

Last, we would appreciate knowing precisely what kind of security measures Midwest Fertilizer is undertaking to assure that none of the product manufactured by the company end up in the hands of terrorists as has happened often from the parent company's (Fatima) in Pakistan, In those cases, product from the Pakistani plant have been used often to maim and kill US troops in Afghanistan.

And frankly, we are left feeling very unassured by IDEM's last minute assurances that there would be zero granular ammonium nitrate storage as stated in Appendix A, Page 15 of 30 of the Technical Support Document as provided in the official draft. Such language being used in an official document as part of a major source cannot be considered simply a typographical error as explained verbally by Mr. Stuckey at the hearing. In fact, for a typo to occur there would not be the use of the word granular at all. This is no minor error since that page clearly alters the supposed purpose of the proposal significantly.

We feel, that this error, if it is in fact an error, is justifiable rationale for the whole public participation process to begin anew with a new public notice and comment period to start once the correction to the permit has been made and a new draft permit placed online and in public libraries open for public inspection. If it is not an error, we are left to wonder why it would make it into the document and whether IDEM was intent on obfuscation and deceit regarding the real purpose of the facility in question.

If this is not done, then the public is left to wonder just what kind of facility is being permitted which slaps the public and required public participation in the face.

#### **IDEM Response**

IDEM, OAQ has responded to comments provided by Mr. Boggs and Mr. Bryant as part of the Valley Watch record comments in the above discussion. See response to comments on health hazards in IDEM's response to public hearing comment No. 1 above and public

comment No. 24 below. IDEM, OAQ does not have the authority to consider site security or terrorism in its review of PSD/New Source Construction and Part 70 Operating Permits.

In regards to the manufacture of granular ammonium nitrate, MFC has never proposed the manufacture of granular ammonium nitrate and will not produce granular ammonium nitrate. An ammonium nitrate solution will be produced and immediately consumed in the manufacture of urea ammonium nitrate. IDEM, OAQ understands the commenter's confusion due to a typographical error in Appendix A to the TSD, page 15 of 30 incorrectly states granular ammonium nitrate in the header of the emission calculation sheet. The header should state "Granular Urea Loadout and Storage Emissions." Revisions to the header are shown below:

Appendix A to the TSD – Page 15 of 30

Appendix A to the Technical Support Document (TSD)  
Granular ~~Ammonium Nitrate~~ Urea Loadout and Storage Emissions

\*\*\*\*\*

IDEM, OAQ has determined that correction of this typographical error does not warrant a second public notice period.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Comment No. 19**

**Manufacture of Granular Ammonium Nitrate**

I skimmed the air permit for the plant and noticed on page 587 of the PDF document (Appendix A to the TSD, page 15 of 30) that granular ammonium nitrate (AN) will be manufactured. If this is true, I have serious concerns about the siting of the facility. At the Posey County Zoning Commission meeting, it was stated that AN would be made but immediately blended to make UAN. If AN is to be stored in the dry state, then there should be no basis for the air permit to be approved because false information was provided to the community. I did contact Midwest and I was informed that the inclusion of AN in the permit was in error. Please correct that error.

**IDEM Response**

IDEM, OAQ addressed the ammonium nitrate concerns in IDEM's Response to Public Comment No. 18. In regards to the location of the plant, IDEM has no authority to regulate the location of the source. Zoning is determined by local government officials and these questions should be posed to them. As long as the Applicant for a Part 70 Operating Permit meets all of the state and federal air pollution permitting requirements, IDEM, OAQ is legally required to issue the permit.

Please see IDEM's Response to Public Comment 18 for a clarification regarding the manufacture of granular ammonium nitrate, which was an error.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Comment No. 20**

**Fugitive Ammonia and Methanol Emissions**

I am concerned with the fugitive emissions of ammonia and methanol and I believe a realistic amount of yearly emissions be communicated to the public.

**IDEM Response**

IDEM, OAQ has no authority to regulate ammonia under 326 IAC 2-2 (PSD). Ammonia is not a VOC or HAP or otherwise listed as a regulated air pollutant under PSD. IDEM, OAQ has no information regarding ammonia emissions from Midwest Fertilizer Corporation. General information regarding ammonia can be located at <http://www.epa.gov/iris/subst/0422.htm> on the U.S. EPA website. Also, see IDEM's Response to Public Comment #16 for a more detailed discussion on regulation of ammonia.

Methanol is a VOC and a HAP and is regulated by IDEM, OAQ. Appendix A to the Technical Support Document (TSD), page 22 of 30, indicates fugitive methanol emissions will be 0.01 tons per year or approximately 20 pounds. Public Health Concerns are addressed in more detail in IDEM's Response to Public Comment No. 24, below.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Comment No. 21**

**Requirements for a Risk Assessment**

It is my firm belief that a risk assessment to the community and environment should be done before the air permit is considered. I don't believe this was done, or if it was, it was not communicated to the general public.

I would like to know if this site is under any jurisdiction of Homeland Security, as they will be producing AN. I go on record that I think the facility is too close to existing neighborhoods and the site chosen is not optimal. I would recommend at least a 0.5 mile buffer zone between a plant of this complexity and homeowners and business owners.

I think that this plant is a positive development for Posey County and the United States in general. I believe that the United States has endeavored to improve the quality of the environment. It appears that the facility in question is being built with state of the art technology and will be run by qualified technologists, so I am confident that it will run safely.

I expect that the company building the facility will educate the public about the processes being practiced, that they will educate local authorities to the nature of the site, that they will teach the community the cadence of their alarm system, that community evacuation plans are in place in the event of a significant ammonia release or in the event of an explosion of the process used to make AN.



### IDEM Response

IDEM, OAQ addressed the ammonium nitrate concerns in IDEM's Response to Public Comment No. 18. IDEM, OAQ understands how important safety concerns are to the local community. With the exception of evaluating the impact of the source emissions on air quality, additional safety considerations are outside the scope of this permit process. In addition, IDEM, OAQ has no authority to regulate the location of the source. Please contact your local government officials for safety and zoning concerns. No revisions to the draft permit are required because of this comment.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### Public Comment No. 22

#### Chemical Storage and Production

I would like to know the amount of UAN, nitric acid, urea, ammonium nitrate, and ammonia (pure liquid ammonia and aqueous ammonia) to be stored on the site on a routine basis. What is the volume of the storage tanks? What is the composition of stored material?

### IDEM Response

Midwest Fertilizer Corporation will produce the following products:

MFC Products	Daily Production (Short Tons per Day)	Composition
Liquid Ammonia	2,646	99.8% ammonia 0.2% water
Liquid Urea (Solution)	2,910	80% Urea 20% Water
Granulated Urea	1,587	99% Granular Urea <1% Biuret < 0.3% Water
Nitric Acid (100% by weight acid solution equivalent basis)	2,028	60% Nitric Acid 40% Water
Urea Ammonium Nitrate (UAN) Solution	5,688	80% UAN 20% Water
Diesel Exhaust Fluid (DEF) 32.5% Basis	1,190	32.5% Urea 67.5% Water

The following table indicates all significant storage tanks:

Tank	Capacity Metric Tons (each tank)	Capacity U.S Tons (each tank)	Bulk Density (lb/Ft <sup>3</sup> )	Estimated Volume (each tank <sup>2</sup> )
2 Ammonia Storage	30,000	33,000	42.57, 1 atm / -24F	11.6 million gallons
3 UAN Storage	40,000	44,000	UAN-28 79.93	8.2 million gallons
1 DEF	7,000	7,700	58.30 32.5% urea	1.98 million gallons
1 MDEA / OASE <sup>(1)</sup>	-----	-----	-----	395,000 gallons
1 Nitric Acid (60% by weight acid equivalent solution)	8,000	8,800	84.88	1.64 million gallons
Diesel Storage	-----	-----	-----	8,700 gallons

(1) OASE is a registered trademark. MDEA is methyl diethanolamine.

(2) The applicant provided volumes for the MDEA and diesel storage tank. IDEM estimated the others

One granular urea storage warehouse is provided to store approximately 30,000 metric tons (33,000 U.S. tons) or 1.5 million cubic feet of granular urea, assuming a tapped bulk density of 0.8 metric tons per cubic meter.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### Public Comment No. 23

#### Time Extension for Review of Documents

I am reviewing the draft permit for Midwest Fertilizer. I am emailing to enquire about the possibility of extending the public comment period. Given the complexity of the facility and the amount of materials to review, will the department extend the comment period for an additional 30 days?

#### IDEM Response

Prior to issuing a Part 70 permit, IDEM, OAQ is required pursuant to 326 IAC 2-7-17(c)(1)(C)(iii) to notify the public of a 30 day period to submit written comments to the commissioner along with a brief description of the comment procedures. IDEM, OAQ had a notice published in the Mt. Vernon Democrat in January 22, 2014 to comply with this requirement. The public comment period ended on March 3, 2014. A total of 45 days was provided for the public to review the draft permit documents and provide comments. Initial PSD/new source construction and Part 70 Operating permits are complex and 45 days was an adequate review period for this level of complexity. A more detailed discussion of the public comment period was provided above in IDEM's Response to Public Comment No. 2.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

**Public Comment No. 24**

**Cancer and General Health Risks in Posey County**

Posey County has one of the highest cancer rates in the county. Our neighbor's baby has been diagnosed with cancer. The last thing we need is a fertilizer plant that emits more carcinogens in the air! Please do not approve 129-33576-00059 or allow this plant to be built. I truly cannot understand why there should be any increased levels of air pollution in the valley. What is the benefit here? And, why aren't vehicles required to have an emissions test annually?

Here in Point Township we have plenty of emissions entering the air daily. The Sabic plastic plant, oil wells and drilling, agricultural spraying, and coal fired power plants in the Ohio Valley put plenty of fumes and particulate into the air we breathe. The occurrence of cancer is very high in our community compared to other locations in Indiana.

I heard some talking about jobs, but, what good are they if you or someone in your family or your neighbors are sick or dead. I say no to more pollution. That is what we do not need. There is a need to clean up what we have here not add more to the mix.

**IDEM Response**

IDEM, OAQ performed air dispersion modeling in Posey County, Indiana to ensure the proposed facility did not pose a threat to public health or the environment. IDEM, OAQ's analysis showed the proposed facility will not significantly impact the ambient air quality in Posey County, Indiana and a significant increase in asthma or cancer is not expected.

**Current Health Information – Asthma and Cancer Rates**

**Asthma Rates – Indiana State Department of Health**

Review of the current data available to the Indiana State Department of Health and IDEM demonstrate that residents of Posey County have not been at increased risk for exacerbation of asthma measured by emergency department and hospitalization encounters. The table below shows the age adjusted rate for asthma. Posey County, Indiana is below the state average for both measures.

<b>Age-adjusted Emergency Department and Inpatient Asthma-related Encounter Rates and Ranks - Posey County, Indiana 2012</b>		
Type of Visit (Based on ICD-9 Code 493 within first 3 diagnoses codes)	Age-adjusted Rate (per 10,000 population)	State Average All Ages
Posey County Asthma-Related Emergency Department Visits	20.8	48.8
Posey County Asthma-Related Inpatient Admits	11.5	11.6

Source: ISDH Epidemiology Resource Center Data Analysis Team (2013), Indiana Hospital Discharge Data Files, 2012

### **Cancer / Respiratory Hazard Rates – 2005 NATA**

#### **National Air Toxics Assessment** (Source: <http://www.epa.gov/ttn/atw/nata2005/tables.html>)

The United States Environmental Protection Agency (U.S. EPA) conducted the most recent National Air Toxics Assessment (NATA) in 2005. The 2005 NATA was made available to the public in early 2011. 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 seven census tracts in Posey 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 for point source cancer in Posey County was ranked 561<sup>th</sup> in the state of Indiana. The highest cancer risk for that census tract from major sources in the NATA was 1.26 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 1.26 extra cancer cases per million people. The average for Posey County from point source cancer is 0.55. Posey County's point source cancer rate is well below the average calculated for Indiana of 2.16 and the national average of 1.48.

The average total respiratory hazard index is 0.83 for Posey County, Indiana. The statewide average is 1.14 and the national average is 2.29. Posey County, Indiana is below the state and national average for total respiratory hazards. Posey County is not subject to excessive cancer, asthma or respiratory hazards as documented by the 2005 NATA.

### **Cancer Rates – Indiana Cancer Registry**

The Indiana Cancer Registry contains a publication called, "Indiana Cancer Facts & Figures 2012." This publication is a source book for planning and implementing programs for cancer prevention and control in Indiana. It was jointly produced by the Data Committee of the Indiana Cancer Consortium (ICC), the Indiana Department of Health, and the American Cancer Society (ACS), Great Lakes Division. Indiana Cancer Facts and Figures 2012 contains the most up to date information available on the impacts of cancer on Indiana residents. The report indicates, "Indiana's age-adjusted cancer incidence rate during 2004 to 2008 was 475.6 per 100,000 people. This was statistically higher than, but very similar to, the national rate of 471.8 per 100,000 people." The report also indicated, "...Indiana's age-adjusted mortality rate was 8% higher than the national rate (195.8 verses 181.3 deaths per 100,000 people)." The report attributed this difference between the Indiana and national incidence and mortality rates to lung cancer associated with smoking. Indiana had the 10<sup>th</sup> highest adult smoking rate in the county. Table 1 is summarized below:

<b>Incidence and Mortality (Death) Rate Comparisons between Indiana and the United States, by Sex and Race, 2004-2008, Age-adjusted</b>						
<b>Population</b>	<b>Incidence Rate per 100,000 people</b>			<b>Mortality Rate per 100,000 people</b>		
	<b>Indiana</b>	<b>United States</b>	<b>Difference</b>	<b>Indiana</b>	<b>United States</b>	<b>Difference</b>
Total	475.6	471.8	+ 0.8%	195.8	181.3	+8.0%
Males	556.2	552.1	+0.7%	245.8	223.1	+10.2%
Females	422.4	415.9	+1.6%	163.6	153.3	+6.7%
Whites	470.0	470.9	-0.2%	194.1	180.0	+7.8%
African Americans	490.7	483.1	+1.6%	236.3	220.9	+7.0%

Sources: Indiana Cancer Facts & Figures 2012 - Table 1

The report indicates progress is being made in the treatment and detection of certain cancers and the age-adjusted mortality and incidence rates are currently on the decline. The table below shows cancer incidence rates for Posey County and the State of Indiana. Posey County is below the state average for the incidence and mortality rates for cancer.

<b>Indiana Cancer Incidence Rates and Mortality Rates 2004 to 2008</b>		
<b>All Cancers</b>		
<b>Population</b>	<b>Incidence Rate</b>	<b>Mortality Rate</b>
State of Indiana	475.6	195.8
Posey County	404.5	192.1

Sources: Indiana Cancer Facts & Figures 2012 - Table 2 and 3.

IDEM, OAQ recognizes that air pollution and its affect on the health of local residents is of great personal concern to the commenter. The Office of Air Quality issues air pollution permits to facilities that emit regulated levels of pollutants to the air. Permits require sources to comply with all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board. If an applicant demonstrates that they will be able to comply with all Federal and State laws regarding air pollution, IDEM is required by law to issue the air permit.

IDEM operates an air pollution permitting program designed to allow the economy of the state to grow while minimizing adverse environmental effects. It is possible to have a growing economy while protecting the environment. The draft permit contains the necessary requirements for limiting and testing of air pollution, operating and monitoring air pollution controls, preventive maintenance of processes and pollution controls, and record keeping and reporting. IDEM OAQ considers pollution control monitoring to be sufficient to assure compliance with the emission limitations on a continuous basis.

The facility will be inspected on a regular basis by a local IDEM Compliance Inspector. If the commenter or citizens have complaints or issues with the source with respect to compliance with its permit conditions, IDEM, OAQ recommends that citizens contact the current Compliance Inspector, which can be found at the following website:

<http://www.in.gov/idem/airquality/2418.htm>.

Complaints can also be submitted to IDEM three (3) different ways:

1. Online at: <http://www.in.gov/idem/5275.htm>;
2. Through the Complaint Coordinator at (800) 451-6027 ext. 24464; or
3. By printing, completing, and mailing a paper-based Complaint Submission Form (Available under Agency Forms at: <http://www.in.gov/idem/5157.htm>)

IDEM, OAQ does not have the authority to consider emissions from mobile sources such as cars and trucks in permitting decisions. Indiana has a vehicle emissions testing program for vehicles registered in Lake and Porter Counties, which were manufactured after 1976, and have a gross vehicle weight rating of 9,000 pounds or less. For more information please call the Clean Air Car Check Vehicle Testing Program at (888) 240-1684 or visit the Clean Air Car Check website at: <http://www.cleanaircarcheck.com>

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of these comments.

#### **Public Comment No. 25**

#### **Reformer Monitoring Requirements**

The Midwest Fertilizer reformer is required to demonstrate compliance with the CO<sub>2</sub> BACT limit in the draft permit by stack testing once. A one-time stack test is not sufficient to demonstrate continuous or on-going compliance with the CO<sub>2</sub> BACT limit of 59.61 tons/MMCF (116.88 lb/MMBtu) based on a three hour average. The best method for demonstrating on-going compliance with the reformer CO<sub>2</sub> BACT limit under all operating scenarios is with a Continuous Emission Monitoring System (CEMS) (as opposed to a one-time test under ideal conditions). Following the CEMS, the accepted hierarchy for compliance demonstration methods is: 1) parametric monitoring, 2) material balance, and 3) stack testing. In addition, considering that the draft permit requires a NO<sub>x</sub> CEMS and a CO<sub>2</sub> or O<sub>2</sub> monitor would be necessary as well to obtain NO<sub>x</sub> emissions continuously; a CO<sub>2</sub> CEMS could be used to satisfy the NO<sub>x</sub> CEMS requirement and to also assure continuous compliance with the CO<sub>2</sub> BACT limit.

The Midwest Fertilizer reformer has no periodic monitoring requirements for the selective catalytic reduction (SCR) NO<sub>x</sub> control device. This NO<sub>x</sub> control device is being used to meet the NO<sub>x</sub> BACT limit of 9 ppm<sub>vd</sub> with a NO<sub>x</sub> CEMS being used to demonstrate continuous compliance with the BACT limit. However, CEMS do experience routine downtime and during those times, the draft permit does not have any method of ensuring that the SCR is operating properly. The best method for ensuring proper SCR operation and optimal NO<sub>x</sub> control is monitoring the ammonia injection rate continuously.

### **IDEM Response**

Permits issued under 326 IAC 2-7 are required by 326 IAC 2-7-5(3) to include monitoring and related record keeping and reporting requirements, which assure that all reasonable information is provided to evaluate continuous compliance with the applicable requirements. Where an applicable requirement does not include sufficient terms, 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. If necessary to assure that all reasonable information is provided to evaluate continuous compliance, additional compliance monitoring requirements may be required. Compliance monitoring requirements are usually required by IDEM, OAQ for emission units with an emission limitation or permit condition requiring the use of a control device. Monitoring parameters are measured properties and may include indicators such as pressure drop, pH, temperature, liquid flow rates, visible emission notations and emission unit throughputs.

IDEM evaluates several criteria when determining the sufficient compliance determination and monitoring requirements for a permit. This is accomplished on a case-by-case basis considering the factors listed below:

- The magnitude of emissions;
- The expected variability of the emissions based on the nature and design of the emission unit and actions of the operator;
- Whether emission control systems are used to reduce emissions (which inherently increases the potential variability of the emissions) or whether emissions are uncontrolled;
- The difference between the expected emission rates and the emission limit or the degree of emission reduction claimed;
- The basis for determining emission values during the permitting process;
- The value of parametric monitoring data to demonstrate performance of emission controls or operation within design variables;
- The value of recordkeeping to satisfy, in whole or in part, the compliance monitoring requirements based on the applicable requirement, particularly for units where emissions are uncontrolled;
- The representativeness of the data obtained by testing or monitoring; and
- The cost of various testing and monitoring schemes in relation to environmental impacts and compliance risk.

In the case of the one-time stack testing identified by the commenter for the natural gas reformer, IDEM determined that one-time testing for CO and energy efficiency and repeat testing of CO<sub>2</sub> is appropriate for the reformer. This testing is appropriate based on several factors:

- These units do not use emission control systems to reduce emissions, so testing determines that the system operates as designed.
- The permit requires recordkeeping and reporting of fuel usage which ensures that only clean-burning natural gas or process off-gases are burned.
- Natural gas-fired equipment is relatively simple to operate and requires a low degree of maintenance to assure long term achievement of good combustion and energy efficiency. Emissions and energy efficiency from the units are expected to be stable over the short term and the performance is not expected to worsen significantly over time.
- CO emission levels are based on design guarantees by the equipment vendor.
- Because there is little expected variability or deterioration of performance.

The commenter is correct in stating that CEMS do experience routine downtime. However, IDEM addresses the procedures to follow for the reformer in Condition D.1.13(d) and (e). The Permittee is required to repair a failed CEMS. IDEM requires a CEMS to be online at all times. If a CEMS breaks, the Permittee is required to notify IDEM and keep records of CEMS downtime and actions taken to place the unit back in service. IDEM reviews this information to determine, on a case-by-case basis, the enforcement action that will be taken.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### **Public Comment No. 26**

#### **Nitric Acid Plant N<sub>2</sub>O BACT and Monitoring**

The N<sub>2</sub>O BACT limit for the Midwest Fertilizer Nitric Acid plant is 0.613 lb/ton acid produced based on SCR control. An SCR is not a N<sub>2</sub>O control device as it does not reduce N<sub>2</sub>O emissions and can in fact, generate additional N<sub>2</sub>O. There are three different levels of N<sub>2</sub>O control that can be applied to Nitric Acid plants:

1. Primary control (gauze modification), which can achieve N<sub>2</sub>O control up to 70%.
2. Secondary control (secondary catalytic), which can achieve N<sub>2</sub>O control up to 90%.
3. Tertiary control (tertiary catalytic), which can achieve N<sub>2</sub>O control over 90%.

The Midwest Fertilizer Nitric Acid Plant BACT decision, explained in appendix B of the technical support portion of the draft permit, does not address N<sub>2</sub>O emissions by including an evaluation of the above control options. One of the above controls are not necessarily required to be selected for BACT but must however, be excluded on an environmental, economic, or technical feasibility basis. Two other recent BACT decisions for Nitric Acid plants (Iowa Fertilizers and Ohio Valley Resources) as seen in the RBLC table included in appendix B, have selected tertiary catalytic systems. IDEM has excluded the need for



Midwest Fertilizer to install add on controls for N<sub>2</sub>O based solely on the fact that the BACT emission limit set for the Midwest Fertilizer Nitric Acid plant is only 60% of the Ohio Valley Resources limit using tertiary N<sub>2</sub>O control. However, the equivalent Iowa Fertilizers N<sub>2</sub>O BACT limit for the Nitric Acid Plant is 0.436 lb/ton and the N<sub>2</sub>O limit established for the Midwest Fertilizer Nitric Acid plant is 40% higher than the Iowa Fertilizers Nitric Acid plant N<sub>2</sub>O limit. Therefore, the N<sub>2</sub>O BACT level selected for the Midwest Fertilizer is not equivalent or better than the Iowa Fertilizers BACT limit. If there is a lower N<sub>2</sub>O emission level and more effective control established as BACT for another source of the same source category, then IDEM is required to explain why the level of N<sub>2</sub>O control set for the Iowa Fertilizers Nitric Acid plant is not appropriate for the Midwest Fertilizer Nitric Acid plant and what distinguishes that plant from the permitted Iowa Fertilizers plant (See page B.29 of the New Source Review Manual - <http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf>).

The Midwest Fertilizer Nitric Acid plant has no periodic monitoring requirements for the selective catalytic reduction (SCR) NO<sub>x</sub> control device. This NO<sub>x</sub> control device is being used to meet the NO<sub>x</sub> BACT limit of 0.064 lb/ton with a NO<sub>x</sub> CEMS being used to demonstrate continuous compliance with the BACT limit. However, CEMS do experience routine downtime and during those times the draft permit does not have any method of ensuring that the SCR is operating properly. The best method for ensuring proper SCR operation and optimal NO<sub>x</sub> control is monitoring the ammonia injection rate continuously.

#### **IDEM Response**

IDEM, OAQ concurs with the commenter's analysis of the technical applicability of SCR. The facility utilizes a hybrid emission control device where two processes occur in a single reactor vessel. In one section N<sub>2</sub>O is catalytically decomposed and in another section NO<sub>x</sub> is reduced by an SCR process. Although it is physically one control device, two separate control functions are carried out. See IDEM Response to EPA Comment No. 6 for a more detailed explanation and revisions to the draft permit because of this comment. The Iowa Fertilizer Company was issued a PSD permit for the Nitric Acid plant on October 26, 2012 and a revised permit was issued on March 13, 2014. The revised permit contained the following NO<sub>x</sub> and N<sub>2</sub>O emission limitations:

N <sub>2</sub> O	98% reduction and 30 ppmv, excluding startup, shutdown and malfunction (SSM) emissions.
NO <sub>x</sub>	5 ppmv, excluding SSM emissions and 30 TPY including SSM emissions.
Production Rate	1,700 MT per day of 100% by weight Nitric Acid Solution

The applicant provided information with the application indicating the N<sub>2</sub>O emission rate approved is for IFC is 54.34 lb/hr or 238 tons per year and the NO<sub>x</sub> emission rate is 39.84 lb/hr or 174 TPY. The revised permit was based on a nitric acid production rate of 77.92 tons of 100% acid per hour. IDEM, OAQ determined the approved NO<sub>x</sub> and N<sub>2</sub>O emission rates of the Iowa Fertilizer Company and the Ohio Valley Resources facilities and the proposed rates for Midwest Fertilizer are as shown in the table below:

<b>N<sub>2</sub>O Emissions from Nitric Acid Unit</b>			
<b>Facility</b>	<b>Production 100% by weight acid equivalent solution (ton/hr)</b>	<b>N<sub>2</sub>O Emission Rate (lb/hr)</b>	<b>N<sub>2</sub>O Emissions (lb/ton) (100% by weight acid equivalent solution)</b>
<b>MFC</b>	<b>84.5</b>	<b>51.83</b>	<b>0.613</b>
IFC	77.92	54.34	0.70
OVR	52.5	55.33	1.05

<b>NO<sub>x</sub> Emissions from Nitric Acid Unit</b>			
<b>Facility</b>	<b>Production 100% by weight acid equivalent solution (ton/hr)</b>	<b>NO<sub>x</sub> Emission Rate (lb/hr)</b>	<b>NO<sub>x</sub> Emissions (lb/ton) (100% by weight acid equivalent solution)</b>
<b>MFC</b>	<b>84.5</b>	<b>5.41</b>	<b>0.064</b>
IFC	77.92	38.95	0.50
OVR	52.5	26.25	0.50

The NO<sub>x</sub> and N<sub>2</sub>O emission rates proposed by Midwest Fertilizer Corporation are significantly lower than the IFC or the OVF facilities. This still represents BACT.

The commenter is correct in stating that CEMS do experience routine downtime. However, IDEM addresses the procedures to follow for the nitric acid plant in Condition D.4.9(c) and (d). The Permittee is required to repair a failed CEMS and IDEM requires a CEMS to be online at all times. If a CEMS breaks, the Permittee is required to notify IDEM and keep records of CEMS downtime and actions taken to place the unit back in service. IDEM reviews this information to determine, on a case-by-case basis, the enforcement action that will be taken.

## **Public Comment No. 27**

### **CO<sub>2</sub> Purification Process**

The Midwest Fertilizer CO<sub>2</sub> purification process is required to demonstrate compliance with the CO<sub>2</sub> BACT limit in the draft permit by stack testing once. A one-time stack test is not sufficient to demonstrate continuous or on-going compliance with the CO<sub>2</sub> BACT limit of 0.0117 lb/ton based on a three hour average and 100% CO<sub>2</sub> in the exhaust. The best method for demonstrating on-going compliance with the CO<sub>2</sub> purification process CO<sub>2</sub> BACT limit is with a Continuous Emission Monitoring System (CEMS) under all operating scenarios rather than a one-time test under ideal conditions. Following the CEMS, the accepted hierarchy for compliance demonstration methods is: 1) parametric monitoring, 2) material balance, and 3) stack testing. Alternatively, if the exhaust can be shown to be 100% CO<sub>2</sub> then a continuous flow meter may be possibly used in place of a CO<sub>2</sub> CEMS.

According to AP-42 Section 8.1.1., the CO<sub>2</sub> Purification / Condensate Stripper is a source of methanol emissions (1.2 lb/ton), which is a Hazardous Air Pollutant (HAP). Neither the Midwest Fertilizer draft permit nor the technical support document addresses methanol emissions for the CO<sub>2</sub> Purification Process. Hexane (HAP) emissions from the entire Midwest Fertilizer plant were limited to less than 10 tons per year and total HAP emissions were limited to less than 25 tons per year in order to be classified as a minor source of HAPs. Because methanol is also a HAP, Midwest Fertilizer must account for methanol emissions from this source and, if present, track emissions on a 12-month rolling basis and sum them with hexane emissions to demonstrate that the 25 tons per year HAP threshold has not been exceeded.

### **IDEM Response**

IDEM, OAQ provided a general discussion of the methods used to determine the correct compliance determination and compliance monitoring requirements, as well as the reasoning behind showing compliance with three hour limits in IDEM Response to Public Comment No. 25. In regards to specific requirements for the CO<sub>2</sub> purification vent, IDEM, OAQ determined one-time testing for CO, VOC and CO<sub>2</sub> were appropriate. This testing is appropriate based on the following factors:

- This emission unit does not use emission controls systems to reduce emissions
- There is little expected variability or deterioration of performance of the process and the data collected by CO or CO<sub>2</sub> CEMS will be of little value.

The applicant provided information in the application indicating methanol emissions will be minimal. Hexane emissions are the primary concern of this source. IDEM, OAQ understands the commenter's concern over the accuracy of the emission factor used by the applicant. In response, IDEM, OAQ added a one-time test for methanol to verify the actual emission rate. See IDEM Response to EPA Comment No. 6 for revisions to the permit because of this comment.

## **Public Comment No. 28**

### **Urea Granulator BACT**

The RBLC tables in appendix B show that the Urea Granulator  $PM_{2.5}$  BACT limit which is over three times lower than the limit established for Midwest Fertilizer Corporation, where the BACT control in both instances is a wet scrubber. The BACT level established for the Midwest Fertilizer granulator is 0.163 lb/ton  $PM_{2.5}$  as opposed to 0.108 lb/ton for CF Industries and 0.05 lb/ton for Iowa Fertilizers. In addition, Iowa Fertilizers BACT limit was established as a fraction (25%) of the total PM/ $PM_{10}$  BACT limit of 0.2 lb/ton. The Midwest Fertilizer BACT limit for  $PM_{2.5}$  is equal to the PM and  $PM_{10}$  BACT limits established. In reality,  $PM_{2.5}$  emissions are some fraction of both total PM and  $PM_{10}$  emissions, therefore the  $PM_{2.5}$  BACT limit established for the Midwest Fertilizer granulator cannot be considered BACT as the achievable  $PM_{2.5}$  emissions should be lower than the total PM and  $PM_{10}$  allowable emissions.

The Midwest Fertilizer draft permit does not include any BACT determinations for opacity with respect to the urea granulator. The Midwest Fertilizer Plant will be a new major source of PM,  $PM_{10}$ , and  $PM_{2.5}$ , where any of these pollutants that are emitted at high enough levels will produce visible emissions. Because the urea granulator emits PM,  $PM_{10}$ , and  $PM_{2.5}$  and is located at a major source, BACT should be evaluated for opacity (visible emissions). If the BACT levels established for PM,  $PM_{10}$ , and  $PM_{2.5}$  are low enough then a no visible emissions BACT limit should be applied as an indicator of proper control device operation.

### **IDEM Response**

MFC proposed a PM,  $PM_{10}$ , and  $PM_{2.5}$  BACT limit of 0.163 lb per ton of urea produced. IDEM, OAQ determined a common BACT limit for all three pollutants was appropriate. As discussed in IDEM's Response to Public Comment No. 15, the Iowa Fertilizer permit (issued by the Iowa DNR) does have a lower  $PM_{2.5}$  limit. However, the Iowa DNR's more recent permit for the CF Industries Nitrogen facility's granulator unit has limits which are the same for PM,  $PM_{10}$  and  $PM_{2.5}$ . We question whether there is sufficient technical justification in the Iowa Fertilizer permit to justify establishing a lower  $PM_{2.5}$  limit. It is more difficult to remove finer particles vs. coarser ones and we find it technically questionable to use a limit for  $PM_{2.5}$  which is significantly lower than that for PM or  $PM_{10}$ .

The CF Industries Nitrogen plant has not been constructed or tested and, until it is, the emission limitations proposed are significantly below other sources and are not proven to be achievable in practice at all times during the life of the granulator. As such, it does not represent BACT for MFC.

The commenter is correct in stating an opacity limit and regular opacity readings may be appropriate for an emission unit subject to a PSD BACT limit for particulate. IDEM, OAQ evaluated the need for an opacity limit and rejected it for the urea granulator. This was a case-by-case determination. A review of the RBLC table listed in the BACT, shows no other facility has established a limit for opacity. The urea granulator is functioning as a product collector and excess emissions indicates product is being lost to the wind. In addition, the granulator is controlled by a wet scrubber that operates at saturation conditions and water vapor would complicate opacity measurements. Pressure drop is an appropriate compliance monitoring parameter for the wet scrubber controlling emissions from the urea granulator.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

#### **Public Comment No. 29**

##### **Cooling Tower BACT**

The Midwest Fertilizer draft permit does not include any BACT determinations for opacity with respect to the cooling towers. The Midwest Fertilizer Plant will be a new major source of PM, PM<sub>10</sub>, and PM<sub>2.5</sub>, where any of these pollutants that are emitted at high enough levels will produce visible emissions. Because the cooling towers emit PM, PM<sub>10</sub>, and PM<sub>2.5</sub> and are located at a major source, BACT should be evaluated for opacity (visible emissions). If the BACT levels established for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> are low enough then a no visible emissions BACT limit should be applied as an indicator of proper control device operation.

##### **IDEM Response**

The commenter is correct in stating an opacity limit and regular opacity readings may be appropriate for an emission unit subject to a PSD BACT limit for particulate. IDEM, OAQ evaluated the need for an opacity limit and rejected it for the cooling towers. This was a case-by-case determination. The uncontrolled potential to emit of the six cell cooling tower is 1.95 TPY of PM, 1.24 TPY of PM<sub>10</sub>, and 4.14E-03 TPY of PM<sub>2.5</sub>. The uncontrolled potential to emit of the ten cell cooling tower is 3.24 TPY of PM, 2.06 TPY of PM<sub>10</sub>, and 0.01 TPY of PM<sub>2.5</sub>. Emissions from these units are at an insignificant level and minimal compliance monitoring is required. Opacity limits in excess of those imposed in Condition C.2 is not warranted. Also, other RBLC entries for cooling towers relied on monitoring the total dissolved solids of the water used in the cooling tower to assure continuous compliance with particulate limits. This is the same approach used by MFC and is appropriate for this unit. Opacity measurements would also be complicated because emissions from the cooling towers will be at saturation conditions. TDS is the appropriate compliance monitoring measure for the cooling towers.

MFC provided a visibility analysis in Section 7.4 of the application. This analysis was performed to demonstrate the proposed project does not cause an impairment of visibility in the local area. MFC used guidance from the U.S. EPA workbook for plume visual impact screening analysis using the plume visibility impact model VISCREEN. This analysis is used to determine if during worst-case meteorological conditions a plume is either imperceptible or if perceptible is not likely to adversely affect local visibility. This analysis showed the plume parcels located inside the boundaries of the receptor grid will not be adversely affected by this project.

No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of this comment.

### **Public Comment No. 30**

#### **Comments of Mark J. Bryant, Valley Watch**

Valley Watch, Inc. statement of purpose is to “protect the public health and environment of the lower Ohio Valley”. Valley Watch stands for a clean and healthy environment and to facilitate our purpose we desire to work hand in hand with the public, government, business and industry to support economic development that does not further degrade our finite environment and negatively impact public health.

These same goals are also reflected in the IDEM mission core statement that reads “to implement federal and state regulations to protect human health and the environment, while allowing the environmentally sound operation of industrial, agricultural, commercial, and governmental activities vital to a prosperous economy.” and there is no reason in this day and age that economic development cannot be advantageous and in the best interests of both the public and business.

The new Midwest Fertilizer, Inc. fertilizer plant that is proposed to be built in Mt. Vernon, Indiana is a very big deal. The cost for the construction of this facility is estimated to be about \$2 billion dollars, provide employment for more than 200 people (from Midwest Fertilizer’s website) and will have a significant impact upon the quality of life for local residents. Any manufacturing process that produces a great amount of hazardous substances such as this Midwest Fertilizer, Inc. facility must undergo proper vetting in the public sphere to ensure that the project meets its design criteria and provides a level of safety and security for the owners of the facility and last but not least those who must work and live within the area of the facility’s operations.

Upon reviewing the permit that was filed by Midwest Fertilizer, Inc. and the conclusions that were reached by the IDEM Draft Permit there remain some looming questions about the impact of this plant upon the environment within the 50 kilometer radius area. Specifically, two sites (Henderson, KY for PM<sub>2.5</sub> data and Evansville, IN for NOx monitoring data) were used for background monitoring data in the IDEM Draft report as agreed to by Midwest and the Office of Air Quality to ultimately conclude that the Midwest Fertilizer, Inc. facility in Mt Vernon would have minimal impact upon the PM<sub>2.5</sub> concentrations within its operating area.

It is unclear why the Midwest Fertilizer, Inc. Draft Permit would use background monitoring data from two different sources and one obvious reason would be to show a smaller impact of dangerous PM<sub>2.5</sub> pollution concentrations by using the Henderson, KY PM<sub>2.5</sub> monitoring data. The first question to ask is would the use of the Evansville, IN

monitoring data for  $PM_{2.5}$  24-hour and annual  $PM_{2.5}$  concentrations change the projected EPA exceedances of the  $PM_{2.5}$  24-hour and  $PM_{2.5}$  annual limits within the 50 kilometer radius area and hence change the conclusion of the permit?

The Southwestern Indiana area is already saturated with industrial facilities that produce and emit gargantuan amounts of toxic gases and particulate pollution. In fact, one monitoring site (University of Evansville – Carson Center) within 19 miles (30 km) from the proposed Midwest Fertilizer, Inc. site already exceeds the Environmental Protection Agency's standard  $PM_{2.5}$  Annual Design Value of  $12.0 \mu\text{g}/\text{m}^3$  by  $0.2 \mu\text{g}/\text{m}^3$ .

Breathing these particles in small quantities for even a few years may reduce the life expectancy of humans by years. It is beyond the scope of this comment to detail and outline the negative health impacts of  $PM_{2.5}$  pollution except to mention the significant increase of stroke, heart attack, asthma and COPD caused by inhaling  $PM_{2.5}$  pollution. This means that the quality of life for all the inhabitants of the new point source area will be negatively impacted and further damage will be done to the common air resource of those living and working within the Midwest 50 kilometer radius area.

Even though the levels of  $PM_{2.5}$  pollution have been declining in recent years these reductions may be temporary and explanations for the recent decreases may not necessarily indicate a long term trend. Therefore, caution is mandated when deciding if a new point source of the deadly and disabling  $PM_{2.5}$  pollution should be emitted within the affected area. If questions remain about the point source  $PM_{2.5}$  concentrations emitted by the Midwest facility, IDEM should then require post construction monitoring of all pollutants discharged from the facility for 5 years until a long term trend may be established.

Remember, we are considering the future health and well-being of our children and grandchildren and their right to a sustainable and healthy future. It is not a question of if the negative impacts of increased  $PM_{2.5}$  pollution concentrations will be unleashed, but only to whom the effects that this unhealthy burden will fall upon. Also, new EPA guidelines on that were recently implemented should be included within the guidelines for the final IDEM permit that will be eventually issued to Midwest.

Even though the Draft Permit approves Midwest in Mt Vernon to operate its plant at its maximum capacity, IDEM has the authority to change the permit and restrict the Midwest plant to operate at an output level that does not increase annual  $PM_{2.5}$  emissions above the annual EPA  $12.0 \mu\text{g}/\text{m}^3$  limit within the 50 kilometer radius area.

Due to the serious and irreversible human health effects of allowing an increase in new point source PM<sub>2.5</sub> pollutants than is currently allowed within the Southwestern Indiana area, IDEM should permit the Midwest facility to operate at such a capacity that will keep its PM<sub>2.5</sub> concentrations below the EPA Annual Design Value of 12.0 µg/m<sup>3</sup> (2010-2012) within the 50 kilometer area radius. The limited operating restrictions should remain until such time that the annual PM<sub>2.5</sub> monitor readings for the entire area fall below the Annual Design Value of 12.0 µg/m<sup>3</sup> (2010-2012).

Valley Watch believes the Midwest facility limited operation permit is the best “environmentally sound” option. Valley Watch thanks the IDEM and OAQ for the opportunity to allow an interested public voice to be heard.

### **IDEM Response**

IDEM's mission is indeed to implement federal and state regulations to protect human health and the environment while allowing for environmentally sound operations of industrial, agricultural, commercial, and government activities vital to a prosperous economy. The draft permit for the Midwest Fertilizer Corporation (MFC) is protective of human health and allows for environmentally sound operations that will promote a prosperous economy in Posey County. A team of IDEM, OAQ staff spent nearly three months evaluating the application submitted by Midwest Fertilizer Corporation before presenting the draft permit documents to the public. IDEM, OAQ has vetted the application and does not believe the facility proposes a significant threat to the environment or the health of those who live and work near it.

In regard to the use of monitoring data, IDEM endeavors to use the best data available. Not all pollutants are obtained at each site, so it is often not possible to obtain all pollutant monitoring data from one location. The only NO<sub>2</sub> data available for this area is from the Evansville – Buena Vista site. Henderson, Kentucky with a population of 27,952 was the PM<sub>2.5</sub> site used as a background site because it is actually closer to the Midwest Fertilizer location, and considered more representative of local conditions in rural Posey County. The University of Evansville site is located in a city with a population 117,429. Further, both Evansville sites include impacts from sources that are also modeled in the 50 km radius, and so using one of these sites would have double-counted some of the emissions.

However, recognizing that Midwest Fertilizer emissions could impact the Evansville sites, an assessment was made of that impact. IDEM desired to use the most recent data available. There were just a few December 2013 PM<sub>2.5</sub> samples remaining to be processed and quality assured for 2013, but based upon non-quality assured data available, it was apparent that the averages for the year were trending lower. Therefore, the assessment was made using that data. The charts below show the final, quality assured data for 2013, which show decreasing values over the past several years and current annual design values below the recently implemented 12.0 ug/m<sup>3</sup> National Ambient Air Quality Standards (NAAQS). The impact from Midwest Fertilizer added to these values will not cause an exceedence of the NAAQS.



**PM<sub>2.5</sub> 24-Hour Monitoring Data Summary**

Site #	Site Name	City	Daily 98th Percentile Values (µg/m <sup>3</sup> )				Three-Year Design Value (µg/m <sup>3</sup> )			
			2010	2011	2012	2013	08-10	09-11	10-12	11-13
181630021	Evansville - Buena Vista	Evansville	30.4	30.0	19.7	23.5	29	29	27	24
181630016	Evansville - U of E	Evansville	29.2	28.0	20.8	24.3	27	28	26	24

**PM<sub>2.5</sub> Annual Monitoring Data Summary**

Site #	Site Name	City	Annual Means (µg/m <sup>3</sup> )				Three-Year Design Value (µg/m <sup>3</sup> )			
			2010	2011	2012	2013	08-10	09-11	10-12	11-13
181630021	Evansville - Buena Vista	Evansville	12.83	11.89	10.79	10.80	12.6	12.4	11.8	11.1
181630016	Evansville - U of E	Evansville	13.40	12.26	11.00	10.6	12.8	12.7	12.2	11.3

The health impacts of PM<sub>2.5</sub> can be significant. PM<sub>2.5</sub> also known as “fine particulate” includes particles with a diameter of 2.5 microns or less. These particles are believed to pose the greatest health threat because their small size allows them to lodge deeply into the lungs. Studies have suggested links between PM<sub>2.5</sub> and health problems including asthma, bronchitis, respiratory symptoms such as shortness of breath and painful breathing, along with premature death. Most of the premature deaths are the elderly who have existing cardiopulmonary diseases or weakened immune systems. IDEM works to protect and improve air quality by maintaining a continuous monitoring network for PM<sub>2.5</sub> and issues advisories for the public when air quality may be unhealthy. IDEM, OAQ modeled emissions from MFC along with sources within a 50 km radius and believes it will not cause or contribute to a violation of the National Ambient Air Quality Standard for PM<sub>2.5</sub> and will be protective of human health and the environment. Finally, IDEM, OAQ concurs with the commenter’s observation that PM<sub>2.5</sub> pollution in this part of the state is on the decline. Additional health effects are addressed in IDEM Response to Public Comment No. 24.

The commenter suggests IDEM, OAQ require post construction monitoring of all pollutants discharged from the facility for five (5) years or until a long term trend of the levels of air pollution can be established. Typically, IDEM, OAQ requires the installation of continuous emissions monitoring systems (CEMS) when they are required by an underlying rule. The applicant may propose the use of a CEMS to facilitate their compliance monitoring burden by reducing labor costs. In the case of MFC, the following monitors are proposed:

- (1) Primary Reformer – NO<sub>x</sub> CEMS installed to facilitate compliance monitoring
- (2) Nitric Acid Plant – NO<sub>x</sub> CEMS pursuant to 40 CFR 60.73a, Subpart Ga
- (3) Auxiliary Boilers – NO<sub>x</sub> CEMS pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions)

In other cases, IDEM, OAQ and the applicant review possible compliance determination and compliance monitoring requirements for each emission unit. Typically, compliance determination requirements for uncontrolled emission units consists of a one-time emissions test if IDEM is convinced the process has little variability or the emission factor is well established. Highly variable processes signal the need for emissions testing on a more regular basis, usually every five (5) years. Testing and compliance monitoring requirements are usually required for emission units with a control device where a CEMS is not required by rule.

IDEM, OAQ established the following compliance determination requirements for Midwest Fertilizer Corporation:

Compliance Determination Requirements		
Emission Unit	Parameter	Frequency
Reformer Furnace (EU-001)	Use of SCR	At all times in operation, except startup and shutdown
	Hexane Record Keeping	Monthly
	CO <sub>2</sub> Emissions Record Keeping	Monthly
Nitric Acid Plant (EU-009)	Use of SCR	At all times in operation, except startup and shutdown
Startup Heater (EU-002)	Hexane Record Keeping	Monthly
Combustion Turbines (EU-013A/B)	CO <sub>2</sub> Emissions Record Keeping	Monthly
Front End Flare (EU-017)	NO <sub>x</sub> , CO, VOC, CO <sub>2</sub> Record Keeping	Monthly
Back End Flare (EU-018)	NO <sub>x</sub> , CO, VOC, CO <sub>2</sub> Record Keeping	Monthly
Ammonia Storage Flare (EU-016)	NO <sub>x</sub> , CO <sub>2</sub> Record Keeping	Monthly
Auxiliary Boilers (EU-012A/B/C)	Low NO <sub>x</sub> Burners Flue Gas Recirculation (FGR)	At all times in operation
	Hexane Record Keeping	Monthly
Urea Granulator (EU-008)	Use Scrubber	At all times in operation
Urea Granule Storage Warehouse (EU-024)	Use Baghouse	At all times in operation
Fugitive Emissions from Equipment Leaks (F-1)	Use Leak Detection and Repair (LDAR) Program	As specified in 40 CFR 60, Subpart VVa

Compliance Determination Requirements		
Emission Unit	Parameter	Frequency
Truck Loading (EU-020)	Use Baghouse	At all times in operation
Rail Loading (EU-021A)	Use Baghouse	At all times in operation
Urea Junction Operation (EU-021B)	Use Baghouse	At all times in operation

Summary of Testing Requirement				
Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency
Reformer Furnace (EU-001)	SCR	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			CO <sub>2</sub>	Every 5 Years
			Thermal Efficiency	One Time
CO <sub>2</sub> Purification Process (EU-003)	None	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			VOC	One Time
			CO <sub>2</sub>	One Time
Nitric Acid Unit (EU-009)	SCR/DeN <sub>2</sub> O	Within 60 days of max. capacity but no later than 180 days after startup	N <sub>2</sub> O	Every 5 Years
Urea Granulator (EU-008)	Wet Scrubber	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Urea Granule Storage Warehouse (EU-024)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Auxiliary Boilers (EU-012A/B/C)	Low NO <sub>x</sub> Burners, FGR	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			CO <sub>2</sub>	One Time

Summary of Testing Requirement				
Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency
			Thermal Efficiency	One Time
Truck Loading (EU-020)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Rail Loading (EU-021A)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Urea Junction (EU-021B)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Combustion Turbines (EU-013A/B)	Low NOx Dry Combustors	Within 60 days after reaching max. capacity, but no later than eighteen (18) months after initial startup of the turbines	NO <sub>x</sub>	Every 5 Years
			CO	One Time
			Thermal Efficiency	One Time
			CO <sub>2</sub>	One Time
		No later than 180 days after startup	NO <sub>x</sub>	One Time
			CO	One Time
			Thermal Efficiency	One Time
			CO <sub>2</sub>	One Time

IDEM, OAQ established the following compliance monitoring requirements:

Summary of Monitoring Requirements			
Emission Units	Parameter	Frequency	Response to Excursions or Exceedances
Reformer Furnace (EU-001)	NO <sub>x</sub>	Continuous	A Reasonable Response
Front End Flare (EU-017)	Presence of Flame	Continuous	A Reasonable Response
Back End Flare (EU-018)	Presence of Flame	Continuous	A Reasonable Response
Ammonia Storage Flare (EU-016)	Presence of Flame	Continuous	A Reasonable Response
Urea Granulation Unit (EU-008)	Pressure Drop	Once per Day	A Reasonable Response
Urea Granule Storage Warehouse (EU-024)	Pressure Drop	Once per Day	A Reasonable Response
Nitric Acid Plant (EU-009)	NO <sub>x</sub>	Continuous	A Reasonable Response
Auxiliary Boilers (EU-012A/B/C)	NO <sub>x</sub>	Continuous	A Reasonable Response
Truck Loading (EU-020)	Pressure Drop	Once per Day	A Reasonable Response
Rail Loading Operation (EU-021A)	Pressure Drop	Once per Day	A Reasonable Response
Urea Junction (EU-021B)	Pressure Drop	Once per Day	A Reasonable Response
Ten Cell Cooling Tower (EU-010)	Total Dissolved Solids	Once per Month	A Reasonable Response
Six Cell Cooling Tower (EU-011)	Total Dissolved Solids	Once per Month	A Reasonable Response
Emergency Generator (EU-014)	Operating Hours	Once per Month	A Reasonable Response
Fire Pump (EU-015)	Operating Hours	Once per Month	A Reasonable Response
Raw Water Pump (EU-063)	Operating Hours	Once per Month	A Reasonable Response

The compliance determination and compliance monitoring requirements established for Midwest Fertilizer Corporation are consistent with other Part 70 Operating Permits issued by IDEM, OAQ and sufficient to assure continuous compliance with all applicable emission limitations.

The applicant defines the maximum operating capacity in the permit application and IDEM, OAQ issues air pollution permits that require sources to comply with all health-based and technology-based standards established by the U.S. EPA and the Indiana Environmental Rules Board. If an applicant demonstrates that they will be able to comply with all Federal and State laws regarding air pollution, IDEM is required by law to issue the air permit. Where required, synthetic minor limits may be incorporated into the permit in order to ensure compliance with these rules. The draft permit shows the applicant is able to comply with all state and federal rules utilizing the capacities submitted in the permit application. Therefore, IDEM, OAQ is legally required to issue the permit. No changes to the draft PSD/New Source Construction and Part 70 Operating Permit are required because of these comments.

**Public Comment No. 31**

**NO<sub>x</sub> BACT for Auxiliary Boilers**

Page 115 of 197 of Appendix B to the Technical Support Document in Step 3 of the BACT, indicates typical NO<sub>x</sub> removal efficiency for low NO<sub>x</sub> burners with flue gas recirculation is 55% to 60%. However, the control efficiency shown in the ranking indicates the control efficiency is up to 90% control. Why?

**IDEM Response**

Boiler manufacturers have made significant progress on passive controls for NO<sub>x</sub> that are similar to the use of SCR. Current guidance from Cleaver Brooks indicates the combination of flue gas recirculation and low NO<sub>x</sub> burners can approach a removal efficiency of 90%. This level of NO<sub>x</sub> removal is identical to SCR and does not have catalyst replacement cost or the cost of urea. IDEM, OAQ is expanding the discussion for the Step 3 of the NO<sub>x</sub> BACT for the auxiliary boilers to provide a more detailed explanation of the higher removal efficiency achieved by low NO<sub>x</sub> burners with flue gas recirculation.

Page 115 of 197 of Appendix B to the Technical Support Document, Step 3 is revised as shown below:

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control technologies for NO<sub>x</sub> control are ranked below:

- (a) Selective Catalytic Reduction – up to 90% control
- (b) Low NO<sub>x</sub> burners with Flue Gas Recirculation – up to 90% control
- (c) Low NO<sub>x</sub> Burners – up to 50% control
- (d) Flue Gas Recirculation – up to 25% control
- (e) Good Combustion Practices – less than 25% control

Typically the combination of low NO<sub>x</sub> burners and flue gas recirculation are capable of achieving 55% to 60% control. The applicant is proposing installation of LNB and FGR to achieve the same level of reduction as SCR. This would represent top BACT.

**To estimate 90% NO<sub>x</sub> emission reduction, IDEM used the uncontrolled NO<sub>x</sub> emission factor from AP-42, Chapter 1.4, Table 1.4-1 SCC 1-02-006-01 of 190 lb NO<sub>x</sub> / MMBtu (0.19 lb/MMBtu). If the practical limit of NO<sub>x</sub> removal were 90%, a boiler would be expected to achieve a NO<sub>x</sub> emission rate of 0.019 lb/MMBtu. The Iowa Fertilizer Corporation proposed a NO<sub>x</sub> emission rate of 0.0125 lb/MMBtu, which represents a 93.4% reduction. This level of reduction exceeds a level IDEM considers practical and achievable at all times over the life of the unit. MFC proposed an emission rate of 0.02 lb/MMBtu or an 89.5% reduction. MFC will achieve the lowest NO<sub>x</sub> emission rate for an auxiliary boiler listed in the RBLC that has been demonstrated in practice. This is top BACT.**

<b>IDEM Contact</b>
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- (a) Questions regarding this proposed permit can be directed to David Matousek 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) 232-8253 or toll free at 1-800-451-6027 extension (2-8253).
- (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](http://www.idem.in.gov).

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emissions Summary Sheet

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 17, 2013

Uncontrolled PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	582.93	487,152	7.70	7.35
Natural Gas Startup Heater	EU-002	0.75	3.02	3.02	0.24	2.18	14.79	72.97	47,401	0.75	0.71
Auxiliary Boiler 1	EU-012A	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
Auxiliary Boiler 2	EU-012B	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
Auxiliary Boiler 3	EU-012C	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	3.86E-03	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	472.09	472.09	472.09	0.00	0.32	0.00	0.00	0	0.32	0.00
Urea Granule Storage	EU-024	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	473.74	1,407,400	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	190.27	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	190.27	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	3.16	0.63	0.16	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	219.63	214,890	0.00	0.00
PTE of Entire Source		555.67	598.16	594.40	7.88	109.97	1,079	1,800.63	4,023,910	25.64	13.21
Title V Major Source Thresholds		NA	100	100	100	100	100	100	100,000	25	10

(Continued Next Sheet)



**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Emissions Summary Sheet**  
(Continued from Previous Sheet)

Controlled PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	45.50	487,152	7.70	7.35
Natural Gas Startup Heater	EU-002	0.75	3.02	3.02	0.24	2.18	14.79	72.97	47,401	0.75	0.71
Auxiliary Boiler 1	EU-012A	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
Auxiliary Boiler 2	EU-012B	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
Auxiliary Boiler 3	EU-012C	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	3.86E-03	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	47.21	47.21	47.21	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Granule Storage	EU-024	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	23.69	70,370	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	0.32	0.06	0.02	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	219.63	214,890	0.00	0.00
Controlled PTE of Entire Source		71.80	116.56	113.23	7.88	109.65	1,079	616.49	2,686,880	25.32	13.21

(Continued Next Sheet)

**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Emissions Summary Sheet**  
(Continued Previous Sheet)

Limited PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	45.50	487,152	7.70	9.83
Natural Gas Startup Heater	EU-002	0.017	0.069	0.069	0.005	0.05	0.34	1.67	1,082	0.02	
Auxiliary Boiler 1	EU-012A	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
Auxiliary Boiler 2	EU-012B	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
Auxiliary Boiler 3	EU-012C	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	0.004	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	47.21	47.21	47.21	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Granule Storage	EU-024	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	23.69	70,370	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	0.32	0.06	0.02	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	0.53	0.53	0.53	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	219.63	214,890	0.00	0.00
Limited PTE of the Entire Source		73.77	113.10	109.77	7.31	104.41	1,043	538.30	2,573,349	23.53	9.90
PSD Major Source Threshold		100	100	100	100	100	100	100	100,000	NA	NA
PSD Significant Level		25	15	10	40	40	100	NA	75,000	NA	NA

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-001 - Natural Gas Reformer

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Combustion

Heat Input	950.64 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Operation at PTE	8,760 hours/yr	or	8,164.32	MMCF/yr	
Limited Operation	8,760 hours/yr	or	8,164.32	MMCF/yr	

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 3% O <sub>2</sub>	Emission Factor Source
PM	1.9 lb/MMCF	7.76	0.00%	7.76	7.76		BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	5.385 lb/MMCF	21.98	0.00%	21.98	21.98		BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	5.385 lb/MMCF	21.98	0.00%	21.98	21.98		BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	2.45	0.00%	2.45	2.45		AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	22.45	0.00%	22.45	22.45		BACT Limit, AP-42, Ch. 1.4
CO	43.45 lb/MMCF	177.37	0.00%	177.37	177.37		BACT Limit
NO <sub>x</sub>	142.80 lb/MMCF	582.93	92.19%	45.50	45.50	9.00	BACT Limit/Applicant Estimate
Benzene	2.10E-03 lb/MMCF	8.57E-03	0.00%	8.57E-03	8.57E-03		AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	4.90E-03	0.00%	4.90E-03	4.90E-03		AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	3.06E-01	0.00%	3.06E-01	3.06E-01		AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	7.35	0.00%	7.35	7.35		AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	1.39E-02	0.00%	1.39E-02	1.39E-02		AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	2.04E-03	0.00%	2.04E-03	2.04E-03		AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	4.49E-03	0.00%	4.49E-03	4.49E-03		AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	5.72E-03	0.00%	5.72E-03	5.72E-03		AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	1.55E-03	0.00%	1.55E-03	1.55E-03		AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	8.57E-03	0.00%	8.57E-03	8.57E-03		AP-42, Ch. 1.4, Table 1.4-3
Total HAP		7.70		7.70	7.70		
CO <sub>2</sub>	59.61 ton/MMCF	486,675	0.00%	486,675	486,675		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	9.18	0.00%	9.18	9.18		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.92	0.00%	0.92	0.92		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		487,152		487,152	487,152		
CO <sub>2</sub> e (2013 Federal GWPs)		487,178		487,178	487,178		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmv NO<sub>x</sub> @ 3%) x 20.9 x Fd x K / (20.9-3) , Fd = 8,710, K = 1.194E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-002 - Natural Gas-Fired Startup Heater

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Combustion

Heat Input	92.50 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation for PTE	8,760 hours/yr	or	794.41	MMCF/yr	
Limited Hours of Operation	200 hours/yr	or	18.14	MMCF/yr	

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	0.75	0.00%	0.75	0.017	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	3.02	0.00%	3.02	0.069	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	3.02	0.00%	3.02	0.069	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.24	0.00%	0.24	0.005	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	2.18	0.00%	2.18	0.05	BACT Limit, AP-42, Ch. 1.4
CO	37.23 lb/MMCF	14.79	0.00%	14.79	0.34	BACT Limit
NO <sub>x</sub>	183.70 lb/MMCF	72.97	0.00%	72.97	1.67	BACT Limit
Benzene	2.10E-03 lb/MMCF	8.34E-04	0.00%	8.34E-04	1.90E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	4.77E-04	0.00%	4.77E-04	1.09E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	2.98E-02	0.00%	2.98E-02	6.80E-04	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.71	0.00%	0.71	0.02	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	1.35E-03	0.00%	1.35E-03	3.08E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	1.99E-04	0.00%	1.99E-04	4.54E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	4.37E-04	0.00%	4.37E-04	9.98E-06	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	5.56E-04	0.00%	5.56E-04	1.27E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	1.51E-04	0.00%	1.51E-04	3.45E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	8.34E-04	0.00%	8.34E-04	1.90E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.75		0.75	0.02	
CO <sub>2</sub>	59.61 ton/MMCF	47,355	0.00%	47,355	1,081	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.89	0.00%	0.89	0.02	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.09	0.00%	0.09	0.00	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		47,401		47,401	1,082	
CO <sub>2</sub> e (2013 Federal GWPs)		47,404		47,404	1,082	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-012A - Auxiliary Boiler 1

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]4
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-012B - Auxiliary Boiler 2

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-012C - Auxiliary Boiler 3

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]4
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
CO<sub>2</sub> Vent and Granulator Alternative Operating Scenarios (EU-003 and EU-008)**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 15, 2013

**Operational Scenario #1**

CO <sub>2</sub> Vent Emissions - EU-003 - Operational Scenario #1							
Pollutant	Production Rate (ton ammonia/yr)	Emission Factor per Ton Ammonia		PTE (TPY)	% Vented to the Atmosphere	Vented PTE (TPY)	Sources
VOC	965,790	0.0558	lb/ton	26.95	100.00%	26.95	Engineering estimate. VOC and CO emissions are shown as uncontrolled. The catalyst is the process.
CO		0.0117	lb/ton	5.65	100.00%	5.65	
CO <sub>2</sub>		1.275	ton/ton	616	100.00%	616	
CO <sub>2</sub> e		2552.3	lb/ton	1,232,475	100.00%	1,232,475	
Methanol		0.018594	lb/ton	8.98	100.00%	8.98	
Total HAP		0.018594	lb/ton	8.98	100.00%	8.98	

Granulator Emissions - EU-008 - Operational Scenario #1								
Pollutant	Production Rate (ton granules/day)	Emission Factor (lb/ton granules)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Sources
PM	0	1.630	lb/ton	0.00	90.00%	0.00	0.00	Engineering estimate, IDEM control efficiency
PM <sub>10</sub>		1.630	lb/ton	0.00	90.00%	0.00	0.00	
PM <sub>2.5</sub>		1.630	lb/ton	0.00	90.00%	0.00	0.00	
VOC		0.0011	lb/ton	0.00	0.00%	0.00	0.00	Engineering estimate
Methanol		0.0011	lb/ton	0.00	0.00%	0.00	0.00	
Total HAP		0.0011	lb/ton	0.00	0.00%	0.00	0.00	

Total Emissions - Scenario #1			
Pollutant	PTE (TPY)	Controlled PTE (TPY)	Limited PTE (TPY)
PM	0.00	0.00	0.00
PM <sub>10</sub>	0.00	0.00	0.00
PM <sub>2.5</sub>	0.00	0.00	0.00
VOC	26.95	26.95	26.95
CO	5.65	5.65	5.65
CO <sub>2</sub> e	1,232,475	1,232,475	1,232,475
Methanol	8.98	8.98	8.98
Total HAP	8.98	8.98	8.98

(Continued on Next Sheet)



**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**CO<sub>2</sub> Vent and Granulator Alternative Operating Scenarios**  
(Continued from Previous Sheet)

**Operational Scenario #2**

**CO<sub>2</sub> Vent Emissions - EU-003 - Operational Scenario #2**

Pollutant	Production Rate (ton ammonia/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	% Vented to the Atmosphere	Vented PTE (TPY)	Sources
VOC	965,790	0.0558	lb/ton	26.95	35.00%	9.43	Engineering estimate. VOC and CO emissions are shown as uncontrolled. The catalyst is the process.
CO		0.0117	lb/ton	5.65	35.00%	1.98	
CO <sub>2</sub>		1.275	ton/ton	616	35.00%	215	
CO <sub>2</sub> e		2,552.3	lb/ton	1,232,475	35.00%	431,366	
Methanol		0.018594	lb/ton	8.98	35.00%	3.14	
Total HAP		0.018594	lb/ton	8.98	35.00%	3.14	

**Granulator Emissions - EU-008 - Operational Scenario #2**

Pollutant	Production Rate (ton granules/yr)	Emission Factor (lb/ton granules)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
PM	579,255	1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	Engineering estimate for controlled and limited emissions. IDEM assumed 95% control efficiency for particulate.
PM <sub>10</sub>		1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	
PM <sub>2.5</sub>		1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	
VOC		0.0011	lb/ton	0.32	0.00%	0.32	0.32		
Methanol		0.0011	lb/ton	0.32	0.00%	0.32	0.32		
Total HAP		0.0011	lb/ton	0.32	0.00%	0.32	0.32		

**Total Emissions - Scenario #2**

Pollutant	PTE (TPY)	Controlled PTE (TPY)	Limited PTE (TPY)
PM	472.09	47.21	47.21
PM <sub>10</sub>	472.09	47.21	47.21
PM <sub>2.5</sub>	472.09	47.21	47.21
VOC	27.26	9.75	9.75
CO	5.65	1.98	1.98
CO <sub>2</sub> e	1,232,475	431,366	431,366
Methanol	9.30	3.46	3.46
Total HAP	9.30	3.46	3.46

**Worst Case PTE - Both Scenario**

Pollutant	Worst Case Controlled PTE (TPY)	Worst Case Limited PTE (TPY)	Worst Case Scenario
PM	47.21	47.21	2
PM <sub>10</sub>	47.21	47.21	2
PM <sub>2.5</sub>	47.21	47.21	2
VOC	26.95	26.95	1
CO	5.65	5.65	1
CO <sub>2</sub> e	1,232,475	1,232,475	1
Methanol	8.98	8.98	1
Total HAP	8.98	8.98	1

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Urea Plant, UAN Plant, and Nitric Acid Plant Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 15, 2013

Urea Plant Scrubber Vent Emissions - EU-006									
Pollutant	Production Rate (ton urea melt/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
CO <sub>2</sub>	1,062,150	0.0060	lb/ton	3.19	0.00%	3.19	3.19	0.006	Engineering Estimate
CO <sub>2</sub> e		0.0060	lb/ton	3.19	0.00%	3.19	3.19	0.006	

UAN Plant Emissions - EU-007									
Pollutant	Production Rate (ton UAN/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
CO <sub>2</sub>	2,076,120	1.00	lb/ton	1,038	0.00%	1,038	1,038	1.00	Engineering Estimate
CO <sub>2</sub> e		1.00	lb/ton	1,038	0.00%	1,038	1,038	1.00	

Nitric Acid Unit Emissions - EU-009									
Pollutant	Production Rate (ton 100% Acid/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
NO <sub>x</sub>	740,220	1.280	lb/ton	473.74	95.00%	23.69	23.69	0.064	Engineering Estimate
N <sub>2</sub> O		12.26	lb/ton	4,538	95.00%	227	227	0.613	
CO <sub>2</sub> e		3,802.65	lb/ton	1,407,400	95.00%	70,370	70,370	190.13	

**Methodology:**

- 1) PTE (TPY) = Production Rate (ton/day) x Emission Factor (lb/ton) x 1 ton/2,000 lb x 365 day/yr
- 2) Controlled PTE (TPY) = Uncontrolled PTE (TPY) x ( 1 - control efficiency )
- 3) Limited PTE (TPY) is determined by enforceable permit conditions.

**Notes:**

- 1) All emission factors are from an engineering estimate. IDEM, OAQ will require emissions testing to verify each emission factor.

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emission Calculations - EU-017 - Front End Flare Pilot Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

**Operating Parameters - External Natural Gas Combustion**

Heat Input 4.00 MMBtu/hr (Emissions for Pilot Only - See Sheet 30 for Venting Emissions)  
 Natural Gas Heat Content 1,020 MMBtu/MMCF  
 Hours of Operation for PTE 8,760 hours/yr or 34.35 MMCF/yr  
 Limited Hours of Operation 8,760 hours/yr or 34.35 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.03	0.00%	0.03	0.03	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.09	0.00%	0.09	0.09	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	6.48	0.00%	6.48	6.48	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	1.19	0.00%	1.19	1.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	2.06E-05	0.00%	2.06E-05	2.06E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	1.29E-03	0.00%	1.29E-03	1.29E-03	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.03	0.00%	0.03	0.03	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	5.84E-05	0.00%	5.84E-05	5.84E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	8.59E-06	0.00%	8.59E-06	8.59E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.89E-05	0.00%	1.89E-05	1.89E-05	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	2.40E-05	0.00%	2.40E-05	2.40E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	6.53E-06	0.00%	6.53E-06	6.53E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.03		0.03	0.03	
CO <sub>2</sub>	116.89 lb/MMBtu	2,048	0.00%	2,048	2,048	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	3.86E-03	0.00%	3.86E-03	3.86E-03	40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		2,050		2,050	2,050	
CO <sub>2</sub> e (2013 Federal GWPs)		2,050		2,050	2,050	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emission Calculations - EU-018 - Back End Flare Pilot Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

**Operating Parameters - External Natural Gas Combustion**

Heat Input 4.00 MMBtu/hr (Emissions for Pilot Only - See Sheet 30 for Venting Emissions)  
 Natural Gas Heat Content 1,020 MMBtu/MMCF  
 Hours of Operation for PTE 8,760 hours/yr or 34.35 MMCF/yr  
 Limited Hours of Operation 8,760 hours/yr or 34.35 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.03	0.00%	0.03	0.03	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.09	0.00%	0.09	0.09	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	6.48	0.00%	6.48	6.48	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	1.19	0.00%	1.19	1.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	2.06E-05	0.00%	2.06E-05	2.06E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	1.29E-03	0.00%	1.29E-03	1.29E-03	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.03	0.00%	0.03	0.03	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	5.84E-05	0.00%	5.84E-05	5.84E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	8.59E-06	0.00%	8.59E-06	8.59E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.89E-05	0.00%	1.89E-05	1.89E-05	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	2.40E-05	0.00%	2.40E-05	2.40E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	6.53E-06	0.00%	6.53E-06	6.53E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.03		0.03	0.03	
CO <sub>2</sub>	116.89 lb/MMBtu	2,048	0.00%	2,048	2,048	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	3.86E-03	0.00%	3.86E-03	3.86E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		2,050		2,050	2,050	
CO <sub>2</sub> e (2013 Federal GWPs)		2,050		2,050	2,050	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emission Calculations - EU-016 - Ammonia Storage Flare Pilot Emissions**

**Company Name: Midwest Fertilizer Corporation**  
**Address: Intersection Old SR 69 and Mackey Ferry Road East**  
**Mt. Vernon, Indiana 47620**  
**Permit Number: T 129-33576-00059**  
**Reviewer: David Matousek**  
**Date: September 26, 2013**

**Operating Parameters - External Natural Gas Combustion**

Heat Input	1.50 MMBtu/hr	(Emissions for Pilot Only - See Sheet 30 for Venting Emissions)
Natural Gas Heat Content	1,020 MMBtu/MMCF	
Hours of Operation for PTE	8,760 hours/yr	or 12.88 MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or 12.88 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.01	0.00%	0.01	0.01	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.05	0.00%	0.05	0.05	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.05	0.00%	0.05	0.05	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	3.86E-03	0.00%	3.86E-03	3.86E-03	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	2.43	0.00%	2.43	2.43	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	0.45	0.00%	0.45	0.45	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.35E-05	0.00%	1.35E-05	1.35E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	7.73E-06	0.00%	7.73E-06	7.73E-06	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	4.83E-04	0.00%	4.83E-04	4.83E-04	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	2.19E-05	0.00%	2.19E-05	2.19E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	3.22E-06	0.00%	3.22E-06	3.22E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	7.09E-06	0.00%	7.09E-06	7.09E-06	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	9.02E-06	0.00%	9.02E-06	9.02E-06	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	2.45E-06	0.00%	2.45E-06	2.45E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.35E-05	0.00%	1.35E-05	1.35E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.01		0.01	0.01	
CO <sub>2</sub>	116.89 lb/MMBtu	768	0.00%	768	768	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.01	0.00%	0.01	0.01	40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	1.45E-03	0.00%	1.45E-03	1.45E-03	40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		769		769	769	
CO <sub>2</sub> e (2013 Federal GWPs)		769		769	769	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Granular Urea Loadout and Storage Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

PM Emissions (TPY)											
Emission Unit Description	Emission Unit ID	Throughput (Ton/yr)	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (lb/hr)	Limited PTE (TPY)	Limit (lb/ton)	Data Source
Truck Loading	EU-020	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.12	0.53	0.00094	AP-42, Ch. 8.3, Table 8.3-2
Rail Loading	EU-021A	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.0016	AP-42, Ch. 8.3, Table 8.3-2
Urea Junction	EU-021B	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.0016	AP-42, Ch. 8.3, Table 8.3-2
Urea Warehouse	EU-024	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.17	0.73	0.0013	AP-42, Ch. 8.3, Table 8.3-2

PM <sub>10</sub> and PM <sub>2.5</sub> Emissions (TPY)											
Emission Unit Description	Emission Unit ID	Throughput (Ton/yr)	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (lb/hr)	Limited PTE (TPY)	Limit (lb/ton)	Data Source
Truck Loading	EU-020	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.12	0.53	0.00094	AP-42, Ch. 8.3, Table 8.3-2
Rail Loading	EU-021A	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.00164	AP-42, Ch. 8.3, Table 8.3-2
Urea Junction	EU-021B	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.00164	AP-42, Ch. 8.3, Table 8.3-2
Urea Warehouse	EU-024	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.17	0.73	0.00130	AP-42, Ch. 8.3, Table 8.3-2

**Methodology:**

- 1) PTE (TPY) = Throughput (ton urea/day) x 365 day/year x emission factor (lb/ton urea) x 1 ton /2,000 lb
- 2) Controlled PTE (TPY) = PTE (TPY) x ( 1 - control efficiency )
- 3) PTE (lb/ton) = Limited PTE (TPY) x 2,000 lb/ton / throughput (ton/year)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-013A - Natural Gas Combustion Turbine

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 1, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	283.00 MMBtu/hr		
Natural Gas Heat Content	1,020 MMBtu/MMCF		
Hours of Operation for PTE	8,760 hours/yr	or	2,430.47 MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	2,430.47 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 15% O <sub>2</sub>	Emission Factor Source
PM	1.90E-03 lb/MMBtu	2.36	0.00%	2.36	2.36		BACT Limit
PM <sub>10</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
PM <sub>2.5</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
SO <sub>2</sub> (S=15 PPM)	1.40E-03 lb/MMBtu	1.74	0.00%	1.74	1.74		AP-42, Ch. 3.1, April 2000, Table 3.1-2a
VOC	7.00E-03 lb/MMBtu	8.68	0.00%	8.68	8.68		BACT Limit
CO	0.03 lb/MMBtu	37.19	0.00%	37.19	37.19		BACT Limit
NO <sub>x</sub>	0.1535 lb/MMBtu	190.27	45.64%	103.43	103.43	22.65	BACT Limit
Benzene	1.20E-05 lb/MMBtu	1.49E-02	0.00%	1.49E-02	1.49E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Toluene	1.30E-04 lb/MMBtu	1.61E-01	0.00%	1.61E-01	1.61E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Xylene	6.40E-05 lb/MMBtu	7.93E-02	0.00%	7.93E-02	7.93E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Formaldehyde	7.10E-04 lb/MMBtu	8.80E-01	0.00%	8.80E-01	8.80E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
1,3-Butadiene	4.30E-07 lb/MMBtu	5.33E-04	0.00%	5.33E-04	5.33E-04		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acetaldehyde	4.00E-05 lb/MMBtu	4.96E-02	0.00%	4.96E-02	4.96E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acrolein	6.40E-06 lb/MMBtu	7.93E-03	0.00%	7.93E-03	7.93E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Ethylbenzene	3.20E-05 lb/MMBtu	3.97E-02	0.00%	3.97E-02	3.97E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Naphthalene	1.30E-06 lb/MMBtu	1.61E-03	0.00%	1.61E-03	1.61E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Polycyclic Aromatic Hydrocarbons	2.20E-06 lb/MMBtu	2.73E-03	0.00%	2.73E-03	2.73E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Total HAP		1.24		1.24	1.24		
CO <sub>2</sub>	116.89 lb/MMBtu	144,890	0.00%	144,890	144,890		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.73	0.00%	2.73	2.73		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.27	0.00%	2.73E-01	2.73E-01		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		145,032		145,032	145,032		
CO <sub>2</sub> e (2013 Federal GWPs)		145,040		145,040	145,040		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmvd NO<sub>x</sub> @ 15%) x 20.9 x Fd x K / (20.9-15), Fd = 8,710, K = 1.194 E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-013B - Natural Gas Combustion Turbine

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 1, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	283.00 MMBtu/hr		
Natural Gas Heat Content	1,020 MMBtu/MMCF		
Hours of Operation for PTE	8,760 hours/yr	or	2,430.47 MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	2,430.47 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 15% O <sub>2</sub>	Emission Factor Source
PM	1.90E-03 lb/MMBtu	2.36	0.00%	2.36	2.36		BACT Limit
PM <sub>10</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
PM <sub>2.5</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
SO <sub>2</sub> (S=15 PPM)	1.40E-03 lb/MMBtu	1.74	0.00%	1.74	1.74		AP-42, Ch. 3.1, April 2000, Table 3.1-2a
VOC	7.00E-03 lb/MMBtu	8.68	0.00%	8.68	8.68		BACT Limit
CO	0.03 lb/MMBtu	37.19	0.00%	37.19	37.19		BACT Limit
NO <sub>x</sub>	0.1535 lb/MMBtu	190.27	45.64%	103.43	103.43	22.65	BACT Limit
Benzene	1.20E-05 lb/MMBtu	1.49E-02	0.00%	1.49E-02	1.49E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Toluene	1.30E-04 lb/MMBtu	1.61E-01	0.00%	1.61E-01	1.61E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Xylene	6.40E-05 lb/MMBtu	7.93E-02	0.00%	7.93E-02	7.93E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Formaldehyde	7.10E-04 lb/MMBtu	8.80E-01	0.00%	8.80E-01	8.80E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
1,3-Butadiene	4.30E-07 lb/MMBtu	5.33E-04	0.00%	5.33E-04	5.33E-04		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acetaldehyde	4.00E-05 lb/MMBtu	4.96E-02	0.00%	4.96E-02	4.96E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acrolein	6.40E-06 lb/MMBtu	7.93E-03	0.00%	7.93E-03	7.93E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Ethylbenzene	3.20E-05 lb/MMBtu	3.97E-02	0.00%	3.97E-02	3.97E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Naphthalene	1.30E-06 lb/MMBtu	1.61E-03	0.00%	1.61E-03	1.61E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Polycyclic Aromatic Hydrocarbons	2.20E-06 lb/MMBtu	2.73E-03	0.00%	2.73E-03	2.73E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Total HAP		1.24		1.24	1.24		
CO <sub>2</sub>	116.89 lb/MMBtu	144,890	0.00%	144,890	144,890		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.73	0.00%	2.73	2.73		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.27	0.00%	2.73E-01	2.73E-01		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		145,032		145,032	145,032		
CO <sub>2</sub> e (2013 Federal GWPs)		145,040		145,040	145,040		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmvd NO<sub>x</sub> @ 15%) x 20.9 x Fd x K / (20.9-15), Fd = 8,710, K = 1.194 E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb



**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emission Calculations - EU-014 - Emergency Generator**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

**Operating Parameters - Diesel Fired Generator**

Engine Output	3,600 HP			
Brake Specific Fuel Consumption	6,597 Btu/Hp.Hr			
Heat Input	23.75 MMBtu/hr			
Diesel Fuel Heat Content	140 MMBtu/kgal			
Hours of Operation PTE	500 hours/yr	or	84.82	kgallon/yr
Hours of Operation Limited PTE	500 hours/yr	or	84.82	kgallon/yr

Diesel Fired Generator - Emission Calculations (TPY)							
Pollutant	Emission Factor		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
PM <sub>10</sub>	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
PM <sub>2.5</sub>	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
SO <sub>2</sub>	0.0015	lb/MMBtu	8.91E-03	0.00%	8.91E-03	8.91E-03	Design Specification
VOC	0.31	g/hp-hr	0.62	0.00%	0.62	0.62	BACT Limit, AP-42, Ch. 3.4
CO	2.61	g/hp-hr	5.18	0.00%	5.18	5.18	BACT Limit
NO <sub>x</sub>	4.46	g/hp-hr	8.85	0.00%	8.85	8.85	BACT Limit
Hazardous Air Pollutants							
Benzene	7.76E-04	lb/MMBtu	4.61E-03	0.00%	4.61E-03	4.61E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Toluene	2.81E-04	lb/MMBtu	1.67E-03	0.00%	1.67E-03	1.67E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Xylene	1.93E-04	lb/MMBtu	1.15E-03	0.00%	1.15E-03	1.15E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Formaldehyde	7.89E-05	lb/MMBtu	4.68E-04	0.00%	4.68E-04	4.68E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Acetaldehyde	2.52E-05	lb/MMBtu	1.50E-04	0.00%	1.50E-04	1.50E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Acrolein	7.88E-06	lb/MMBtu	4.68E-05	0.00%	4.68E-05	4.68E-05	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Naphthalene	1.30E-04	lb/MMBtu	7.72E-04	0.00%	7.72E-04	7.72E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Total HAP			8.86E-03		8.86E-03	8.86E-03	
Greenhouse Gas Emissions							
CO <sub>2</sub>	526.39	g/hp-hr	1,044	0.00%	1,044	1,044	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	3.00E-03	kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	6.00E-04	kg/MMBtu	7.85E-03	0.00%	7.85E-03	7.85E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)			1,048		1,048	1,048	
CO <sub>2</sub> e (2013 Federal GWPs)			1,048		1,048	1,048	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-015 - Fire Water Pump

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Diesel Fired Pump

Engine Output	500 HP				
Brake Specific Fuel Consumption	7,280 Btu/Hp.Hr				
Heat Input	3.64 MMBtu/hr				
Diesel Fuel Heat Content	140 MMBtu/kgal				
Hours of Operation PTE	500 hours/yr	or	13.00	kgallon/yr	
Hours of Operation Limited PTE	500 hours/yr	or	13.00	kgallon/yr	

Diesel Fired Pump - Emission Calculations (TPY)							
Pollutant	Emission Factor		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
PM <sub>10</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
PM <sub>2.5</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
SO <sub>2</sub>	0.0015	lb/MMBtu	1.37E-03	0.00%	1.37E-03	1.37E-03	Design Specification
VOC	0.141	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
CO	2.60	g/hp-hr	0.72	0.00%	0.72	0.72	BACT Limit
NO <sub>x</sub>	2.83	g/hp-hr	0.78	0.00%	0.78	0.78	BACT Limit
Hazardous Air Pollutants							
Benzene	9.33E-04	lb/MMBtu	8.49E-04	0.00%	8.49E-04	8.49E-04	AP-42, Ch. 3.3, Table 3.3-2
Toluene	4.09E-04	lb/MMBtu	3.72E-04	0.00%	3.72E-04	3.72E-04	AP-42, Ch. 3.3, Table 3.3-2
Xylene	2.85E-04	lb/MMBtu	2.59E-04	0.00%	2.59E-04	2.59E-04	AP-42, Ch. 3.3, Table 3.3-2
Formaldehyde	1.18E-03	lb/MMBtu	1.07E-03	0.00%	1.07E-03	1.07E-03	AP-42, Ch. 3.3, Table 3.3-2
Acetaldehyde	7.67E-04	lb/MMBtu	6.98E-04	0.00%	6.98E-04	6.98E-04	AP-42, Ch. 3.3, Table 3.3-2
Acrolein	9.25E-05	lb/MMBtu	8.42E-05	0.00%	8.42E-05	8.42E-05	AP-42, Ch. 3.3, Table 3.3-2
Naphthalene	8.48E-05	lb/MMBtu	7.72E-05	0.00%	7.72E-05	7.72E-05	AP-42, Ch. 3.3, Table 3.3-2
Total HAP			3.41E-03		3.41E-03	3.41E-03	
Greenhouse Gas Emissions							
CO <sub>2</sub>	527.40	g/hp-hr	145	0.00%	145	145	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	3.00E-03	kg/MMBtu	0.01	0.00%	0.01	0.01	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	6.00E-04	kg/MMBtu	1.20E-03	0.00%	1.20E-03	1.20E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)			146		146	146	
CO <sub>2</sub> e (2013 Federal GWPs)			146		146	146	

### Methodology:

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

## Appendix A to the Addendum to the Technical Support Document (ATSD) Emission Calculations - EU-063 - Raw Water Pump

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Diesel Fired Pump

Engine Output	500 HP				
Brake Specific Fuel Consumption	7,280 Btu/Hp.Hr				
Heat Input	3.64 MMBtu/hr				
Diesel Fuel Heat Content	140 MMBtu/kgal				
Hours of Operation PTE	500 hours/yr	or	13.00	kgallon/yr	
Hours of Operation Limited PTE	500 hours/yr	or	13.00	kgallon/yr	

Diesel Fired Pump - Emission Calculations (TPY)							
Pollutant	Emission Factor		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3
PM <sub>10</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3
PM <sub>2.5</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3
SO <sub>2</sub>	0.0015	lb/MMBtu	1.37E-03	0.00%	1.37E-03	1.37E-03	Design Specification
VOC	0.141	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3
CO	2.60	g/hp-hr	0.72	0.00%	0.72	0.72	BACT Limit
NO <sub>x</sub>	2.83	g/hp-hr	0.78	0.00%	0.78	0.78	BACT Limit
Benzene	9.33E-04	lb/MMBtu	8.49E-04	0.00%	8.49E-04	8.49E-04	AP-42, Ch. 3.3, Table 3.3-2
Toluene	4.09E-04	lb/MMBtu	3.72E-04	0.00%	3.72E-04	3.72E-04	AP-42, Ch. 3.3, Table 3.3-2
Xylene	2.85E-04	lb/MMBtu	2.59E-04	0.00%	2.59E-04	2.59E-04	AP-42, Ch. 3.3, Table 3.3-2
Formaldehyde	1.18E-03	lb/MMBtu	1.07E-03	0.00%	1.07E-03	1.07E-03	AP-42, Ch. 3.3, Table 3.3-2
Acetaldehyde	7.67E-04	lb/MMBtu	6.98E-04	0.00%	6.98E-04	6.98E-04	AP-42, Ch. 3.3, Table 3.3-2
Acrolein	9.25E-05	lb/MMBtu	8.42E-05	0.00%	8.42E-05	8.42E-05	AP-42, Ch. 3.3, Table 3.3-2
Naphthalene	8.48E-05	lb/MMBtu	7.72E-05	0.00%	7.72E-05	7.72E-05	AP-42, Ch. 3.3, Table 3.3-2
Total HAP			3.41E-03		3.41E-03	3.41E-03	
CO <sub>2</sub>	527.40	g/hp-hr	145	0.00%	145	145	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	3.00E-03	kg/MMBtu	6.02E-03	0.00%	6.02E-03	6.02E-03	40 CFR 98, Table C-2
N <sub>2</sub> O	6.00E-04	kg/MMBtu	1.20E-03	0.00%	1.20E-03	1.20E-03	40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)			146		146	146	
CO <sub>2</sub> e (2013 Federal GWPs)			146		146	146	

### Methodology:

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emission Calculations - EU-010 and EU-011 - Cooling Towers**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

Emission Unit	Description	Circulation Rate (GPM)	Drift Factor (%)	Solids Content (mg/l)	Pollutant	Mass Fraction (%)	Annual Emissions (TPY)
EU-011	Six Cell Cooling Tower	88,762	0.0005%	2,000	PM	100%	1.95
					PM <sub>10</sub>	63.50%	1.24
					PM <sub>2.5</sub>	0.213%	4.14E-03
EU-010	Ten Cell Cooling Tower	147,937	0.0005%	2,000	PM	100%	3.24
					PM <sub>10</sub>	63.50%	2.06
					PM <sub>2.5</sub>	0.213%	6.91E-03

**Methodology:**

- 1) PM<sub>10</sub> and PM<sub>2.5</sub> mass fractions were estimated using, "Calculating Realistic PM<sub>10</sub> Emissions from Cooling Towers," by Reisman, J. and Frisbie, G.
- 2) PM emissions (lb/hr) = Q (GPM) x 60 min/hr x 8.34 lb/gallon x solids concentration (mg/l / 1E06) x Drift % / 100
- 3) PM Emissions (TPY) = PM Emissions (lb/hr) x 4.38 ton-hr/lb-yr
- 4) PM<sub>10/2.5</sub> = PM Emissions (TPY) x mass %

## Appendix A to the Addendum to the Technical Support Document (ATSD) Potential Emissions from Component Leaks

**Company Name: Midwest Fertilizer Corporation**

**Address: Intersection Old SR 69 and Mackey Ferry Road East**

**Mt. Vernon, Indiana 47620**

**Permit Number: T 129-33576-00059**

**Reviewer: David Matousek**

**Date: October 2, 2013**

Summary of Potential Fugitive Leaks (TPY)						
Pollutant	Reformer and Ammonia Units	aMDEA Area	UAN Plant Area 1	UAN Plant Area 2	UAN Product Storage Area	Total Emissions
CO	0.07	0.00	0.00	0.00	0.00	0.07
NO <sub>x</sub>	0.00	0.00	0.00	8.23E-03	0.00	0.01
VOC	0.00	3.64	8.84	0.00	1.91	14.39
Methanol	9.39E-03	0.00	0.00	0.00	0.00	0.01
CO <sub>2</sub>	39.68	0.00	3.91	0.49	0.00	44.08
CH <sub>4</sub>	7.20	0.00	0.00	0.00	0.00	7.20
N <sub>2</sub> O	0.00	0.00	0.00	3.29	0.00	3.29
CO <sub>2</sub> e (2009 GWPs)	190.93	0.00	3.91	1,021	0.00	1,215
CO <sub>2</sub> e (2013 GWPs)	219.74	0.00	3.91	981	0.00	1,205

### 1) Reformer and Ammonia Units

Component	Type Service	Emission Factor (lb/hr/component t)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	170	9.80
	Light Liquid	0.00888	210	8.17
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealless	0.04387	8	1.54
	Light Liquid Single Seal	0.04387	0	0.00
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	292	1.10
	Light Liquid	0.00024	35	0.04
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	2	4.40
Relief Valves	Rupture Disk	0.22928	18	18.08
	Gas/Vapor	0.22928	2	2.01
Open Ended Lines	---	0.00375	111	1.82
Sampling Ports	---	0.03307	0	0.00
<b>Total Fugitive Emissions</b>				<b>46.95</b>

Fugitive Emissions Reformer and Ammonia Units		
Pollutant	Mass % Total	PTE (TPY)
CO	0.14%	0.07
NO <sub>x</sub>	0.00%	0.00
VOC	0.00%	0.00
Methanol	0.02%	9.39E-03
CO <sub>2</sub>	84.51%	39.68
CH <sub>4</sub>	15.34%	7.20
N <sub>2</sub> O	0.00%	0.00

### Methodology:

- 1) See Sheet 23

(Continued Next Sheet)

**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**2) aMDEA Area**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	0	0.00
	Light Liquid	0.00888	0	0.00
	Heavy Liquid	0.00051	152	0.34
Pumps	Light Liquid Sealless	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	0	0.00
	Heavy Liquid Single Seal	0.019	9	0.75
Flanges	Gas/Vapor	0.00086	0	0.00
	Light Liquid	0.00024	0	0.00
	Heavy Liquid	0.000001	750	3.29E-03
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	2	2.01
Open Ended Lines	---	0.00375	8	0.13
Sampling Ports	---	0.03307	28	4.06
<b>Total Fugitive Emissions</b>				<b>7.29</b>

<b>aMDEA Potential Fugitive Emissions</b>		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	50.00%	3.64
Methanol	0.00%	0.00
CO <sub>2</sub>	0.00%	0.00
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

- 1) Fugitive Emissions (TPY) = Emission Factor (lb/hr/component) x Number Components x 4.38 ton-hr/lb-year
- 2) Pollutant Emissions (TPY) = Total Fugitive Emission (ton/yr) x Mass % pollutant

**Notes:**

- 1) Emission Factors from Table 2-1, Protocol for Equipment Leak Emission Estimated, EPA 453/R-95-017, November 1995.

(Continued Next Sheet)

**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**3) UAN Plant Area 1**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	82	4.73
	Light Liquid	0.00888	196	7.62
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealess	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	6	1.15
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	132	0.50
	Light Liquid	0.00024	238	0.25
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	6	6.03
Open Ended Lines	---	0.00375	0	0.00
Sampling Ports	---	0.03307	2	0.29

**Total Fugitive Emissions      20.57**

UAN Plant Area 1 Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	43.00%	8.84
Methanol	0.00%	0.00
CO <sub>2</sub>	19.00%	3.91
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

1) See Sheet 23

(Continued Next Sheet)

**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**4) UAN Plant Area 2**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	82	4.73
	Light Liquid	0.00888	196	7.62
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealless	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	6	1.15
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	132	0.50
	Light Liquid	0.00024	238	0.25
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	6	6.03
Open Ended Lines	---	0.00375	0	0.00
Sampling Ports	---	0.03307	2	0.29
<b>Total Fugitive Emissions</b>				<b>20.57</b>

UAN Plant Area 2 Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.04%	8.23E-03
VOC	0.00%	0.00
Methanol	0.00%	0.00
CO <sub>2</sub>	2.39%	0.49
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	16.00%	3.29

**Methodology:**

- 1) See Sheet 23

(Continued Next Sheet)



**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**5) UAN Product Storage**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	0	0.00
	Light Liquid	0.00888	110	4.28
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealess	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	2	0.38
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	0	0.00
	Light Liquid	0.00024	260	0.27
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	0	0.00
Open Ended Lines	---	0.00375	22	0.36
Sampling Ports	---	0.03307	0	0.00
<b>Total Fugitive Emissions</b>				<b>5.30</b>

UAN Product Storage Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	36.00%	1.91
Methanol	0.00%	0.00
CO <sub>2</sub>	0.00%	0.00
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

- 1) See Sheet 23

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Fugitive Particulate Emissions from Paved Roads and Parking Lots**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

Average Vehicle Weight Calculation							
Vehicle Type	Trucks/Day	Average Weight (tons)	Total Trips per Year	Miles per Trip	Vehicle Miles Traveled (VMT) (miles/year)	Traffic Component (%)	Component Weight (tons)
Bulk Truck	250	26.00	91,250	0.114	10,402.50	100.00%	26.00

Total VMT (miles/year)	10,402.50
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W - Average Vehicle Weight (ton)	26.00
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**Site Specific Constants**

Value Name	Symbol	Value	Units	Source
Emission Factor	E	---	lb/VMT	Calculated
Particle Size Multiplier	k for PM	0.011	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Particle Size Multiplier	k for PM <sub>10</sub>	0.0022	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Particle Size Multiplier	k for PM <sub>2.5</sub>	0.00054	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Silt Loading	sL (Average)	2.35	grain/cubic meter	Provided by Applicant, Higher than AP-42, Ch. 13.2.1
Days >0.01" of rain	P	125	days	AP-42, Ch 13.2.1, Figure 13.2.1-2, 01/2011
Total Days in Period	N	365	days	Days in Year
Mean Vehicle Weight	W	26.00	ton	Calculated Above

(Continued on Next Sheet)

**Appendix A to the Addendum to the Technical Support Document (ATSD)**  
**Fugitive Particulate Emissions from Paved Roads and Parking Lots**  
(Continued)

**Average Emission Factors**

AP-42, Chapter 13.2.1-5, 01/2011, Equation 2

$$E = [ k * (\text{Average sL})^{0.91} * (W)^{1.02} ] * [ 1 - P/(4 * N) ]$$

E for PM (lb/VMT) = 0.61 lb/VMT

E for PM<sub>10</sub> (lb/VMT) = 0.12 lb/VMT

E for PM<sub>2.5</sub> (lb/VMT) = 0.03 lb/VMT

**Uncontrolled Potential to Emit**

PM (TPY) = [Annual Average E for PM (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 3.16 TPY

PM<sub>10</sub> (TPY) = [Annual Average E for PM<sub>10</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.63 TPY

PM<sub>2.5</sub> (TPY) = [Annual Average E for PM<sub>2.5</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.16 TPY

**Controlled Potential to Emit**

Control Efficiency 90% based on BACT Limit

PM (TPY) = [Annual Average E for PM (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.32 TPY

PM<sub>10</sub> (TPY) = [Annual Average E for PM<sub>10</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.06 TPY

PM<sub>2.5</sub> (TPY) = [Annual Average E for PM<sub>2.5</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.02 TPY

**Appendix A to the Addendum to the Technical Support Document (ATSD)  
Emissions Summary Sheet - Insignificant Activities - Storage Tanks**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 2, 2013

Uncontrolled PTE of Storage Tanks (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Ammonia Storage Tank	EU-032	Pressurized Tanks - No Normal Emissions									
Ammonia Storage Tank	EU-033										
UAN Storage Tank	EU-034	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
UAN Storage Tank	EU-035	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
UAN Storage Tank	EU-036	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
DEF Storage Tank	EU-037	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
OASE/MDEA Storage Tank	EU-043	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
Nitric Acid Storage Tank	EU-054	0.00	0.00	0.00	0.00	negl.	0.00	0.13	0.00	negl.	0.00
Diesel Fuel Storage Tank	EU-066	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.00	0.00	negl.	negl.
<b>Storage Tanks Total</b>		<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>2.00E-03</b>	<b>0.00</b>	<b>0.13</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>

## Appendix A to the Addendum to the Technical Support Document (ATSD) Startup, Shutdown and Maintenance Emissions

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 17, 2013

### 1) Ammonia Storage Flare (EU-016)

Annual Hours of Venting 168 hours per year  
 Maximum Ammonia Feed Rate 9,075 lb ammonia per hour  
 Maximum Flare Heat Input 69.18 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub> - Thermal	0.068 lb/MMBtu	0.40		AP-42, Ch. 13.5, Table 13.5-1
NO <sub>x</sub> - Fuel	0.01325 lb NO <sub>x</sub> / lb Ammonia	10.10		Design Specification
Total NO <sub>x</sub> Emissions		10.50	125.00 lb/hr	
N <sub>2</sub> O	1.00E-04 kg CO <sub>2</sub> /MMBtu	1.28E-03	negligible	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		0.40	negligible	
CO <sub>2</sub> e (2013 Federal GWPs)		0.38		

### 2) Front End Flare (EU-017)

Annual Hours of Venting 336 hours per year  
 Maximum Flare Heat Input 8,757.20 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub>	0.068 lb/MMBtu	100.04	595.49 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
VOC	0.0054 lb/MMBtu	7.94	47.26 lb/hr	AP-42, Ch. 1.4, Table 1.4-2
CO	0.37 lb/MMBtu	544.35	3,240.16 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO <sub>2</sub>	53.02 kg/MMBtu	171,967	511.81 ton/hr	40 CFR 98, Subpart C, Table C-1
CH <sub>4</sub>	1.00E-03 kg/MMBtu	3.24		40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.32		40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		172,136		
CO <sub>2</sub> e (2013 Federal GWPs)		172,145		

### 3) Back End Flare (EU-018)

Annual Hours of Venting 336 hours per year  
 Maximum Ammonia Feed Rate 36,000 lb ammonia per hour  
 Maximum Flare Heat Input 2,175.07 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub> - Thermal	0.068 lb/MMBtu	24.85		AP-42, Ch. 13.5, Table 13.5-1
NO <sub>x</sub> - Fuel	0.01325 lb NO <sub>x</sub> / lb Ammonia	80.14		Design Specification
Total NO <sub>x</sub> Emissions		104.99	624.94 lb/hr	
VOC	0.0054 lb/MMBtu	1.97	11.73 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO	0.37 lb/MMBtu	135.20	804.76 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO <sub>2</sub>	53.02 kg/MMBtu	42,712	127.12 ton/hr	40 CFR 98, Subpart C, Table C-1
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.81		40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.08		40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		42,754		
CO <sub>2</sub> e (2013 Federal GWPs)		42,756		

SSM Summary (TPY)			
VOC	CO	NO <sub>x</sub>	GHG-2009
9.91	679.55	215.53	214,890

ATSD SSM Emissions			
Original	Reformer	Nitric Acid Plant	New Total
215.53	2.5	1.6	219.63

#### Methodology:

- 1) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x 1 ton/2,000 lb
- 2) PTE (TPY) = Throughput (lb/hr) x Emission Factor (lb/lb) x hr/yr x 1 ton/2,000 lb
- 3) PTE (lb/hr) = PTE (TPY) x 2,000 lb/ton x ( 1 / hr/yr)

**Indiana Department of Environmental Management  
Office of Air Quality**

**Appendix B to the Addendum to the Technical Support Document (ATSD)  
BACT Analysis**

<b>Source Background and Description</b>
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Road East Mt. Vernon, Indiana 47620
County:	Posey County
SIC Code:	2873 (Nitrogenous Fertilizers)
Permit Number:	T129-33576-00059
Permit Reviewer:	David Matousek

<b>Proposed Construction</b>
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On August 26, 2013, Midwest Fertilizer Corporation submitted an air permit application to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The application proposed the construction of a nitrogen fertilizer manufacturing facility located in Mt. Vernon, Indiana. The proposed nitrogen fertilizer manufacturing facility is capable of producing anhydrous ammonia, nitric acid, liquid urea, diesel exhaust fluid (DEF), granulated urea, and urea ammonium nitrate (UAN) solutions. Final products will be shipped from the facility by truck and/or rail. The source will be categorized as a major source for Prevention of Significant Deterioration (PSD) and an area source of Hazardous Air Pollutants (HAPs). Construction will be subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)).

<b>Requirement for Best Available Control Technology (BACT)</b>
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326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) requires a Best Available Control Technology (BACT) review for construction of any new PSD major stationary source that will have major and significant amounts of air pollution for any criteria pollutant. Major means emitting or have the potential to emit 100 tons per year (TPY) or more of any criteria pollutant for sources specifically listed in the PSD regulations. Midwest Fertilizer Corporation is classified as a chemical process plant which is a specifically listed source in the PSD regulations. Significant refers to threshold levels listed in the PSD regulations and assigned to each criteria pollutant, certain non-criteria pollutants and pollutants subject to regulation like greenhouse gases (GHGs).

The construction of the proposed facility will have major emissions of PM (before control), PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and NO<sub>x</sub> and will have GHG emissions that are greater than 100,000 TPY as CO<sub>2</sub>e and subject to regulation under PSD. The proposed facility will have significant emissions of PM (after control) and VOC. The significant levels are 25 tons per year for PM and 40 tons per year for VOC. BACT analyses were performed for PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, NO<sub>x</sub>, VOC and GHGs.

<b>BACT Review – Subject Units</b>
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**Emission Units**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.
  - (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.
- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.
- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.
- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.
- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]
- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.
- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]
- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively. [40 CFR 60, Subpart KKKK]
- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]

- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1. [40 CFR 60, Subpart VVa]
- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.
- (l) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-021A.
- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

#### **Insignificant Activities**

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]
- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]
- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]
- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]
- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]
- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]
- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tank does not contain an organic liquid. [326 IAC 2-2]



- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]

<b>Summary of the Best Available Control Technology (BACT) Process</b>
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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, Midwest Fertilizer Corporation will be required to demonstrate that the emissions will be reduced to the 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. Midwest Fertilizer Corporation has not submitted any innovative control technology for consideration. Only available and proven control technologies were 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 and any more stringent limits established from other RBLC Permits.

### **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 economic or environmental analysis. In no case can the selected BACT be less stringent than any New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or Reasonably Available Control Technologies (RACT) standard or emission limit.

### **Step 5: Select BACT**

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. The final BACT determination would be the technology with the most stringent corresponding limit that is economically feasible. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

## **BACT Analysis – Reformer Furnace (EU-001)**

### **Emission Unit Description**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.

### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) microns (PM<sub>10</sub>), and particulate matter with an aerodynamic diameter less than or equal to two and one half (2.5) microns (PM<sub>2.5</sub>) are generally controlled with an add-on control device designed to capture the emissions before they are exhausted to the atmosphere. The most common add-on control technologies are shown below:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses)

The choice of which technology is most appropriate for a specific application will depend on numerous factors, including: the size of particle, particle loading, desired collection efficiency, stack gas flow rate and the physical properties of the stack gas. Important stack gas properties include: temperature, moisture content, and the presence of reactive materials. For combustion units, it is not unusual for a source to use alternate control measures in place of the above listed control technologies. One or more alternative methods of control may be considered when they are more cost effective than add-on controls or when add-on control may not be feasible. IDEM, OAQ and the applicant have evaluated the following alternative control methods:

- (a) Fuel Specifications - Clean Burning Fuel; and
- (b) Good Combustion Practices.

#### **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<sub>10</sub> in the reformer furnace (EU-001) exhaust is very low (~0.005 gr/cf), a cyclone is not a technically feasible control option for the reformer furnace (EU-001).

(b) **Wet Scrubber**

Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas streams 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 ppm<sub>v</sub>. (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. A wet scrubber is not a technically feasible control option for the reformer furnace (EU-001).

(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<sup>3</sup>. Since the pollutant concentration of the reformer furnace (EU-001) exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control. An electrostatic precipitator is not a technically feasible control option for the reformer furnace (EU-001).

(d) **Fabric Filter Dust Collectors (Baghouse)**

A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A 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 control device for this source. A fabric filter dust collector is not a technically feasible control option for the reformer furnace (EU-001).

(e) **Fuel Specifications – Clean Burning Fuel**

Clean burning natural gas has a very low potential for generating PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions. Fuel specifications are technically feasible control option for the reformer furnace (EU-001).

(e) **Good Combustion Practices / Combustion Controls**

Good combustion practices as well as operation and maintenance of the reformer furnace to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the reformer furnace (EU-001):

(a) Fuel Specifications – Clean Burning Fuel

(b) Good Combustion Practices

The applicant intends to use natural gas as well as good combustion practices to minimize particulate emissions from the reformer. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Reformer Furnace (EU-001) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr natural gas	PM/PM <sub>10</sub> /PM <sub>2.5</sub> - 0.0024 lb/MMBtu 11.9 TPY, rolling 12 month total	Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	PM-1.9 lb/MMCF PM <sub>10</sub> -5.385 lb/MMCF PM <sub>2.5</sub> -5.385 lb/MMCF based on 3-hr avg.	Use Natural Gas/Process Gas, Proper Design, Good Combustion

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Reformer Furnace (EU-001) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Primary Reformer	1,006.40 MMBtu/hr	1.9, 7.6 and 7.6 lb/MMCF, PM/PM <sub>10</sub> /PM <sub>2.5</sub> , respectively 3 hr avg.	Good Combustion Practices, natural gas/process gas
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas Vent	1,412 MMBtu/hr	PM <sub>10</sub> - 0.0075 lb/MMBtu, 3 hour avg.	Proper Design, Operation, and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Methane Reformer	337 MMBtu/hr	PM <sub>10</sub> - 0.0075 lb/MMBtu, 1 hr avg.; 2.52 lb/hr	Combust Gaseous Fuel Only
OK-0135	Pryor Plant Chemical Company	02/23/09	Primary Reformer	700 ton ammonia/day 225 MMBtu/hr	PM-1.68 lb/hr PM <sub>10</sub> -1.26 lb/hr	None

#### **RBLC Review**

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate any source is using add-on control technologies for PM/ PM<sub>10</sub>/PM<sub>2.5</sub> emissions from natural gas-fired reformers or furnaces. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate for PM will be 1.9 lb/MMCF from a natural gas-fired reformer. The Iowa Fertilizer Company has the lowest listed emission rates for PM, PM<sub>10</sub> and PM<sub>2.5</sub>.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Fuel Specifications – Natural Gas / Process Gas Combustion
- (b) Good Combustion Practices, Proper Design; and
- (c) An emission rate of 1.9, 5.385 and 5.385 lb/MMCF for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, a lower rate is proposed for PM<sub>10</sub>, and PM<sub>2.5</sub>. The specific design of this reformer allows for a lower PM<sub>10</sub> and PM<sub>2.5</sub> emission rate. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu (approximately 2.45 lb/MMCF). The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 1.9, 5.385 and 5.385 lb/MMCF, based on a three-hour average for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

#### **Step 5: Select BACT**

IDEM has established BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for reformer furnace (EU-001) as follows:

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams; and
- (c) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall not exceed 1.9, 5.385 and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the reformer furnace (EU-001) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction (SCR)
- (b) Selective Non-Catalytic Reduction (SNCR)
- (c) Low NO<sub>x</sub> Burner (LNB)

One or more alternative methods of control may be considered when they are more cost effective than add-on controls or when add-on control may not be feasible. IDEM, OAQ and the applicant have evaluated the following alternative control methods for all combustion units in this application:

- (a) Good Combustion Practices.

These add-on control technologies and combustion control approaches are discussed below.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Selective Catalytic Reduction**

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  $\text{NO}_x$  to nitrogen and water. Under optimal conditions, SCR has removal efficiencies 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 typically operates 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 ammonia to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional  $\text{NO}_x$ . SCR efficiency is also largely dependent on the stoichiometric molar ratio of Ammonia:  $\text{NO}_x$ ; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%. Selective catalytic reduction (SCR) is a technically feasible control option for the reformer furnace (EU-001).

### **(b) Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR),  $\text{NO}_x$  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, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the  $\text{NO}_x$  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  $\text{NO}_x$  reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms  $\text{NO}_x$  becomes significant. At a lower temperature, the rates of  $\text{NO}_x$  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  $\text{NO}_x$  control performance 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. The exhaust gases from the reformer furnace are used to preheat the influent streams to the reformer in its convection section. This reduces the reformer exhaust to 325 °F which is well below the activation temperature necessary for the reaction to begin and move to completion. The relatively low temperature of the reformer furnace flue gas renders the use of SNCR technically infeasible.

### **(c) Low $\text{NO}_x$ Burners (LNB)**

Using LNB can reduce formation of  $\text{NO}_x$  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  $\text{NO}_x$  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. The use of a low  $\text{NO}_x$  burner is a technically feasible control option for the reformer furnace (EU-001).

(d) **Good Combustion Practices / Combustion Controls**

Good combustion practices as well as operation and maintenance of the reformer furnace to keep it in good working order per the manufacturer's specifications will minimize NO<sub>x</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following control technologies have been identified and ranked for the control of NO<sub>x</sub> from the reformer furnace (EU-001).

- (a) SCR (90% Control)
- (b) Low NO<sub>x</sub> Burners (40% Control)
- (c) Good Combustion Practices (Less than 40% Control)

The applicant proposes the use of SCR along with good combustion practices and low NO<sub>x</sub> burners to control NO<sub>x</sub> emissions from the reformer furnace (EU-001). Therefore, a ranking or further analysis is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Vent	1,412.5 MMBtu/hr	0.0125 lb/MMBtu, annual average	Ultra-Low NO <sub>x</sub> Burner
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	9 ppm <sub>vd</sub> @ 3% oxygen, on a 30 day rolling average, except during startup and shutdown when the catalyst temperature is below operating range.	Good Combustion / Design, natural gas/process gas, low NO <sub>x</sub> burners, SCR
T147-32322-00062	Ohio Valley Resources	09/25/13	Methane Primary Reformer	1,006.4 MMBtu/hr	9 ppm <sub>vd</sub> on a 30 day rolling average	Good Combustion, natural gas, SCR
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr, 1,152.6 MMBtu/hr	9 ppm <sub>v</sub> on a 30 day rolling average, 56 TPY (12-mo rolling avg.)	SCR



RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	0.0125 lb/MMBtu, 4.21 lb/hr @ 3% O <sub>2</sub> ; both 3 hr avg.	SCR
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day	0.2 lb/MMBtu; 11.93 lb/hr (3-hr, 168 rolling cumulative)	Low NO <sub>x</sub> Burner, Good Combustion

### RBLC Review

The applicant proposes the use of SCR to control emissions of NO<sub>x</sub> to 9 ppm<sub>vd</sub> @ 3% oxygen. RBLC entries for reformers at fertilizer plants are limited and not all of the units listed directly correspond to the process proposed by Midwest Fertilizer Corporation. The Garyville Refinery reformer is based on hydrogen as a primary fuel, while the Midwest Fertilizer Corporation reformer will primarily combust natural gas. Hydrogen reformers have a cleaner fuel which results in lower emissions. The Midwest Fertilizer Corporation reformer cannot combust hydrogen without a change in process design. Therefore, the Garyville BACT will not be considered BACT for Midwest Fertilizer.

Ohio Valley Resources and the Iowa Fertilizer Company both proposed the use of SCR for control and methane as the primary fuel. Neither of these facilities have been constructed and they have not passed stack testing for NO<sub>x</sub>. However, IDEM, OAQ found NO<sub>x</sub> BACT for a reformer furnace at a nitrogenous fertilizer facility to be 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average during the PSD BACT review of the Ohio Valley Resources facility.

The Artesia Refinery BACT is a much smaller reformer and it only obtains 70% control of NO<sub>x</sub> using SCR. Also, Midwest Fertilizer Corporation will achieve a higher level of control when compared to the Pryor Plant Chemical BACT.

### Applicant Proposal

The applicant proposes the following as BACT:

- NO<sub>x</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation; and
- NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average; and
- Work Practice Standards during SSM.

### Step 5: Select BACT

IDEM, OAQ has established NO<sub>x</sub> BACT for reformer furnace (EU-001) as:

- NO<sub>x</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;

- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (c) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
- (d) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range; and
- (e) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:
  - (1) **Startup:**

Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its “minimum safe stable load” which is defined as that operating condition when:

    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
    - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
  - (2) **Shutdown:**

Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.
  - (3) **Malfunction:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following CO control technologies for the reformer furnace (EU-001):

- (a) Regenerative Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) 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 °F to 2,000 °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 Oxidizers 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.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the reformer furnace; because, the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

### **(b) 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 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 require approximately 1.5 to 2.0 ft<sup>3</sup> of catalyst per 1000 standard ft<sup>3</sup> gas flow.

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  $\text{SO}_2$  to  $\text{SO}_3$  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. The use of a catalytic oxidizer is a technically feasible control option for the reformer furnace (EU-001).

(c) **Flare**

The low heating value of the reformer furnace (EU-001) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including  $\text{NO}_x$ . Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is not a technically feasible option for the reformer furnace (EU-001).

(d) **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 reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

- (a) Oxidation Catalyst – 75% destruction efficiency
- (b) Combustion Control (Less than 75% Control)

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Reformer Furnace (EU-001) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0194 lb/MMBtu, 3 run avg. 96.3 tons 12 month rolling	Good Combustion
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	43.45 lb/MMCF, 3 hr avg.	Good Combustion, Nat gas/process gas

[illegible]

IDEM, OAQ has determined that the use of a catalytic oxidizer to reduce CO emissions for this emission unit is not cost effective.

The applicant's proposal is consistent with a majority of the entries in the RBLC for CO. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM, OAQ believes BACT for natural gas-fired combustion in the reformer is 43.45 lb/MMCF for CO.

#### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the reformer furnace (EU-001) as:

- (a) CO emissions from the operation of the reformer furnace (EU-001) shall be controlled by the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or off gas streams; and
- (c) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the reformer furnace (EU-001):

- (1) Thermal Oxidation;
- (2) Catalytic Oxidation;
- (3) Flares; and

(4) Good Combustion Practices.

Each of these control technologies is discussed in Step 2 below.

**Step 2: Eliminate Technically Infeasible Options**

(a) **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 and is considered a technology for controlling VOC emissions. Upon passing through the flame, the gas containing VOC 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 VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-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 °F to 2,000 °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 Oxidizers 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%). It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a technically feasible control option for the reformer furnace (EU-001).

(b) **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 and is considered 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 the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft<sup>3</sup> of catalyst per 1,000 standard ft<sup>3</sup> gas flow.

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 SO<sub>2</sub> to SO<sub>3</sub> and subsequent combination with moisture in the

exhaust gas. The use of an oxidation catalyst to control VOC 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. Due to the lower operating temperature requirements, it is possible to use catalytic oxidizers on reformer exhaust gases. While it is physically feasible to use catalytic oxidation, it is not normally used to control VOC emissions from natural gas combustion due to excessive costs associated with raising the temperature of a low heating value gas. The use of a catalytic oxidizer for is not a technically feasible control option for the reformer furnace (EU-001).

(c) **Flare**

The low heating value of the reformer furnace (EU-001) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The use of a flare is not a technically infeasible option for the reformer furnace (EU-001).

(d) **Combustion Control**

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 VOC 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 reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has identified a single control technology for VOC control from the reformer furnace (EU-001). Therefore, no ranking is necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0014 lb/MMBtu, 3 run avg.; 6.95 ton/ 12 month rolling	Good Combustion Practices
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas Vent	1,412.50 MMBtu/hr	0.0015 lb/MMBtu, 3 hr average	Proper Design, Operation and Good Combustion Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.	Proper Design, Good Combustion, natural gas / process gas



RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	Ohio Valley Resources	09/25/13	Methane Primary Reformer	1,006.4 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.	Proper Design, Operation, Good Combustion, Usage Limit
OK-0134	Pryor Plant Chemical	02/23/09	Primary Reformer EUID #101	700 ton ammonia per day; 225 MMBtu/hr	1.2 lb/hr	None
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day, 225 MMBtu/hr	1.21 lb/hr	None
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer	337 MMBtu/hr	0.0050 lb/MMBtu 1.69 lb/hr; 1 hr avg.	Combust Gaseous Fuel Only

#### RBLC Review

A review of the RBLC entries for similar units indicates add-on controls are not typical for this type of emission unit. The entries center on proper design and good combustion practices to ensure complete combustion. While the Garyville Refinery is lower, it uses a hydrogen rich fuel which is a different technology from the methane fuel used at Midwest Fertilizer Corporation, Ohio Valley Resources and the Iowa Fertilizer Company.

#### Applicant Proposal

The applicant proposed the following for BACT:

- (a) Reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (b) VOC emissions from the reformer furnace (EU-001) shall be controlled by good combustion practices and proper design; and
- (c) VOC emissions shall not exceed 5.5 lb/MMCF.

The applicant's proposal is consistent with a majority of the entries in the RBLC for VOCs. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

- (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
- (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM, OAQ believes VOC BACT for natural gas-fired combustion in the reformer furnace (EU-001) is 5.5 lb/MMCF with the use of natural gas/process off gases and good combustion practices.

#### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the reformer furnace (EU-001) as:

- (a) VOC emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams; and
- (c) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the reformer furnace (EU-001):

- (a) Carbon Capture and Sequestration (CCS) and Sale of CO<sub>2</sub>
- (b) Combustion of methane containing off-gas streams as fuel;
- (c) Energy Efficient Design and Combustion Practices; and
- (d) Use a low carbon fuel.

#### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Carbon Capture and Sequestration (CCS) and Sale of CO<sub>2</sub>**  
CCS would be used to capture CO<sub>2</sub> from the exhaust, purify, compress, and transport via pipeline to either a storage location or another pipeline for use in Enhanced Oil Recovery (EOR). CCS involves four main steps as follows:
  - (1) The capture of CO<sub>2</sub> from sources including combusted exhaust streams and the CO<sub>2</sub> vent;
  - (2) The cleanup of emission streams to remove impurities to meet pipeline specifications and to compress the CO<sub>2</sub> to pipeline conditions;
  - (3) The transport of compressed CO<sub>2</sub> to a sequestration site; and
  - (4) Sequestration of the CO<sub>2</sub>.

To determine the cost effectiveness of CCS for this project, IDEM, OAQ made some best case assumptions in calculating the amount of greenhouse gases that were available for capture. IDEM, OAQ assumed all greenhouse gases generated by the facility could be cost effectively collected, concentrated to near pure carbon dioxide, and transported to the nearest pipeline for use in enhanced oil recovery. The entire source has the limited potential to emit 2,573,349 tons per year of GHG as CO<sub>2</sub>e.

After the greenhouse gas emissions have been collected and concentrated to near pure carbon dioxide, the gas must be sequestered. Sequestration can involve either injection into underground geologic formations for storage or for use in enhanced oil recovery. Sequestration for Midwest Fertilizer Corporation would require the establishment of onsite sequestration sites or the construction of a pipeline to transport the greenhouse gases to another sequestration site.

IDEM, OAQ begins its analysis of carbon capture and sequestration by determining if this control technology is feasible. When considering if a control technology is technically feasible, it must be available and applicable. A control technology is applicable if it can be reasonably be installed and operated on the source type under consideration. If a given technology has not been used on the emission unit, thought should be given on transferring technology from similar gas streams with the same physical and chemical properties.

For a technology to be considered available, consideration should be given to:

- (a) Land acquisition;
- (b) The need for federal funding;
- (c) Available transportation infrastructure; and
- (d) Developing a site for long term storage.

#### **Land Acquisition – Long Term Storage Reservoirs**

Storage reservoirs for sequestration of greenhouse gases typically use coal seams at coal mines no longer in operation, saline deposits and oil and natural gas fields. The oil industry has used carbon dioxide floods in enhanced oil recovery efforts for years. This is proven technology and is in common use today. The use of coal seams and saline deposits for underground sequestration is relatively new. This technology is still in the research phase. For Midwest Fertilizer Corporation, there are no proven sequestration sites in the local area and underground storage is not available to Midwest Fertilizer Corporation.

In regards to land acquisition for pipeline construction, Midwest Fertilizer Corporation would have to obtain easements from other entities to allow installation and future maintenance of the pipeline. These easements would be permanent and would prevent property owners from constructing permanent structures over the pipeline.

#### **Federal Funding**

In the past, grants have been available from the U.S. Department of Energy for development of carbon sequestration technologies. There are several sites in southern Indiana currently in the research phase. These projects required federal funding because the technology was prohibitively expensive for private sector participation. Midwest Fertilizer Corporation does not believe federal funding is available for this project's construction timeline.

### Available Transportation Infrastructure

Existing infrastructure to support the transportation of purified CO<sub>2</sub> off site does not exist. Therefore, transportation of the CO<sub>2</sub> stream would require the construction of a pipeline to the nearest sequestration site. The nearest pipeline to a sequestration site is located in Jackson, Mississippi and is operated by Denbury Resources, Inc. Jackson, Mississippi is located approximately 490 miles to the southwest of Mt. Vernon, Indiana, along traveled roads.

Two other projects in the Rockport, Indiana area have received construction and operation permits from IDEM, OAQ in the past year. One was for Indiana Gasification and the other was for Ohio Valley Resources. The Indiana Gasification project proposed a cross country pipeline to transport liquefied carbon dioxide to the Gulf Coast for use in enhanced oil recovery. This project has been delayed and may not be constructed. A GHG BACT analysis for the Ohio Valley Resource project showed the use of carbon capture and sequestration was not an available option. Rockport, Indiana is approximately 50 miles to the east of Mt. Vernon, Indiana. The business plans of the three facilities are completely independent of each other. The construction of the Midwest Fertilizer Corporation facility will proceed regardless of the construction of the other two facilities.

As discussed above, CCS is not feasible for Midwest Fertilizer Corporation because it is not available.

### Sale of CO<sub>2</sub>

The most practical use of captured CO<sub>2</sub> is in the oil and gas industry. CO<sub>2</sub> has been used in enhanced oil recovery for several years. An economic analysis for the Ohio Valley Resources project estimated construction costs of a CO<sub>2</sub> transmission pipeline at approximately \$250.00 per linear foot of pipe installed and approximately \$3,450,000 dollars per year in operating costs. Using the same basis, construction costs for the Midwest Fertilizer Corporation pipeline are estimated at \$646,800,000 for a 490 mile pipeline.

Control Alternative	Captured Emissions (TPY CO <sub>2</sub> e)	Emission Reduction (TPY CO <sub>2</sub> e)	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
CCS	2,573,349	2,573,349	\$646,800,000	\$3,450,000	\$92,091,384 + \$3,450,000 = \$95,541,384	\$37.13 / ton	- Taking of right of way from property owners - Land erosion from underground construction activities
Capital Recovery Factor = 0.14238 ( 7% for a 10 year life cycle)							

The capital cost for pipeline construction represents approximately 50% of the construction cost of the entire fertilizer facility. IDEM, OAQ has determined the sale of CO<sub>2</sub> is not feasible for Midwest Fertilizer Corporation because the pipeline cannot reasonably be constructed and operated by Midwest Fertilizer Corporation. Carbon capture and sequestration and sale of CO<sub>2</sub> are not technically feasible options for this facility; because, they are not available or applicable as described above.

(b) **Combustion of Methane as Fuel**

The combustion of process waste gases containing methane will destroy any methane in the streams, as well as other organic material, and generate CO<sub>2</sub>. Since methane has a higher GWP than CO<sub>2</sub>, the result is a reduction in greenhouse gas emissions as CO<sub>2</sub>e. The use of combustion of methane as fuel is considered feasible for the reformer furnace (EU-001).

(c) **Energy Efficient Design and Combustion Practices**

The use of good design and combustion practices will ensure the reformer furnace (EU-001) is operating as efficiently as possible. Efficient operation ensures emissions of greenhouse gases are minimized. Some of the design and combustion practices available to Midwest Fertilizer Corporation for use in the reformer furnace (EU-001) are:

- (1) Heat from the primary convection section of the reformer can be used to preheat the feed gas to the reformer.
- (2) The reformer could use inlet air controls to limit excess air. Limiting excess air increases combustion efficiency by reducing the amount of air that must be heated during combustion.
- (3) The reformer can be designed to achieve 80% thermal efficiency (HHV basis).
- (4) The reformer furnace can be maintained in accordance with manufacturer recommendations.

Energy efficient design and combustion practices are considered feasible for the reformer furnace (EU-001).

(d) **Use of a Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has selected all feasible control options.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Reformer Furnace (EU-001) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Reformer Furnace (EU-001)</b>	<b>950.6 MMBtu/hr</b>	<b>CO<sub>2</sub>-59.61 ton/MMCF, 3 hour avg., 486,675 ton CO<sub>2</sub> /12 month rolling and 80% Thermal Efficiency (HHV)</b>	<b>Good Design, Good Combustion, Use Natural Gas/Process Gas</b>
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	Primary Reformer	1,006.4 MMBtu/hr	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. CO <sub>2</sub> emissions limited to 515,246 tons/12 month period; 90% thermal efficiency (LHV)	Good Design, Good Combustion, use natural gas/process gas
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr	CO <sub>2</sub> -117 lb/MMBtu, 30 day avg.; CH <sub>4</sub> - 0.0023 lb/MMBtu N <sub>2</sub> O - 0.0006 lb/MMBtu, both 3 run avg.; CO <sub>2</sub> e - 596,905 Ton 12 month rolling	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-108 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr, 5,000,000 ton DRI/yr	CO <sub>2</sub> – 11.79 MMBtu/ton of DRI	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-208 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr, 5,000,000 ton DRI/yr	CO <sub>2</sub> – 11.79 MMBtu/ton of DRI	Good Combustion Practices
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Steam Methane Reformer	216 MMBtu/hr	CO <sub>2</sub> e – 183,784 Ton, 12 month rolling	Good Combustion Practices, Efficient Design

#### **RBLC Review**

All of the entries in the RBLC rely upon good combustion practices as the main control method for greenhouse gases. The Midwest Fertilizer Corporation proposal is typical of recently issued GHG BACT analysis for natural gas-fired reformers.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) MWF proposes the combustion of natural gas and methane containing process off-gas streams in the reformer, good design and combustion practices. MWF proposes an emission limitation of 486,675 TPY of CO<sub>2</sub>e.

The emission rates in the table above are all consistent with emission factors published in the greenhouse gas reporting rule. It appears all facilities used standard emission factors as the BACT limit for greenhouse gas emissions from the reformer furnace.

### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the reformer furnace as:

- (a) GHG emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (c) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
- (d) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows;
- (e) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
- (f) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Reformer Furnace (EU-001)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the operation of the reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (2) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;

- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall not exceed 1.9, 5.385 and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
- (4) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
- (5) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range;
- (6) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average;
- (7) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
- (8) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
- (9) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet stream flows;
- (10) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
- (11) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.
- (12) **During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:**
  - (a) **Startup:**

Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its “minimum safe stable load” which is defined as that operating condition when:

    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and



- (iii) **The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.**
- (b) **Shutdown:**  
**Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.**
- (c) **Malfunction**  
**During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.**

<b>BACT Analysis – CO<sub>2</sub> Purification Process (EU-003)</b>
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**Emission Unit Description**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
- (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> PSD Applicability**

The CO<sub>2</sub> purification process does not have a potential to emit particulate. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the CO<sub>2</sub> purification process for PM, PM<sub>10</sub> and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> PSD Applicability**

The CO<sub>2</sub> purification process does not have a potential to emit NO<sub>x</sub>. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the CO<sub>2</sub> purification process for NO<sub>x</sub> and a BACT analysis is not required for these pollutants.

**CO BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for the CO<sub>2</sub> purification process (EU-003):

- (a) Optimum conversion from CO to CO<sub>2</sub> by use of a catalyst and good operational practices.

Only one control technology was identified in the RBLC. Optimum conversion is discussed below.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Optimum CO Conversion**

CO emissions can be minimized by optimum catalytic conversion of CO to CO<sub>2</sub> in the high end and low end shift converters. The use of an efficient process catalyst and good operational procedures are technically feasible control options.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The only control technology available to the CO<sub>2</sub> purification process (EU-003) is the use of an efficient catalyst and good operational procedures. The applicant has accepted the only feasible control technology. Therefore, no ranking is required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA CO<sub>2</sub> Purification Process (EU-003) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>CO<sub>2</sub> Purification Vent (EU-003)</b>	<b>2,646 ton ammonia per day</b>	<b>0.0117 lb/ton ammonia, 3 hr avg., 100% CO<sub>2</sub> venting</b>	<b>Use Catalyst, Good Operation Practices</b>
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification Process EU-004	3,570 tons of CO <sub>2</sub> per day	0.0117 lb/ton ammonia, 3 hr avg.; 1,022,000 tons/12 month rolling	Use Catalyst, Good Operational Practices
IA-0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,300 ton/day Ammonia	0.02 lb/ton Ammonia, 3 run avg.; 9.65 ton/12 month rolling	Good Operational Practices
LA-0236	Donaldson Nitrogen Complex	03/03/09	#1 to #4 Carbon Dioxide Vents	Tons Ammonia/day #1/#2– 1,620 each #3/#4– 1,785 each	#1 - 5.59 lb/hr #2 – 5.59 lb/hr #3 – 5.08 lb/hr #4 – 5.95 lb/hr; 6.55 TPY	Optimum Catalytic Conversion of CO to CO <sub>2</sub>

### **RBLC Review**

Entries in the RBLC table above indicate add-on control devices are not included in the BACT determinations. The entries show BACT as the optimum conversion of CO to CO<sub>2</sub> by proper selection of a production catalyst and good operational practices. The applicant is proposing an emission rate that is the same as the recently issued Ohio Valley Resources, LLC CO BACT.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and

- (b) CO emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% venting.

The applicant is required to use the Best Available Control Technology. In this case, BACT for emission units constructed and tested is the proper selection of a production catalyst and the use of good operational practices. The applicant has proposed both control measures. In regards to the emission rate for BACT, the applicant must comply with the lowest emission rate achieved in general practice, after considering cost, energy and environmental factors. IDEM, OAQ determined BACT for the CO<sub>2</sub> purification process (EU-003) during the Ohio Valley Resources, LLC BACT determination. However, it is noted that this limit has not been demonstrated in practice and if unachievable, the BACT determination may require future revision. The applicant has accepted all control methods and the lowest emission rate.

IDEM, OAQ recognizes the emission rates proposed by Iowa Fertilizer Corporation and Ohio Valley Resources are much lower than the actual emission rate of the Donaldson Nitrogen Complex. The applicant has accepted the lower emission rate at this time. However, IDEM, OAQ may reopen the BACT for CO if the lower emission rate cannot be achieved in practice.

#### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) CO emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) CO emissions shall not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the CO<sub>2</sub> purification process (EU-003):

- (1) Thermal Oxidation;
- (2) Flares; and
- (3) Proper Selection of Process Catalyst.

Each of these control technologies is discussed below in Step 2.

#### **Step 2: Eliminate Technically Infeasible Options**

(a) **Thermal Oxidizers**

Regenerative thermal oxidation is effective at controlling VOC emissions and is typically used to control waste streams containing organics. Thermal oxidizers are designed to maintain a stable flame through combustion of a combination of waste gases, auxiliary fuel, and supplemental air. For the CO<sub>2</sub> vent the flow of gas to be controlled is very high and 95% of this stream is CO<sub>2</sub> with another 2% as water vapor. Neither of these constituents are combustible. Therefore, combustion of this stream to control the dilute amount of VOCs is technically infeasible.

The use of a thermal oxidizer is not a technically feasible control option for the CO<sub>2</sub> purification process (EU-003).

(b) **Flare**

The low heating value of the CO<sub>2</sub> purification process vent (EU-003) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC.

The use of a flare is not a technically infeasible option for the CO<sub>2</sub> purification process (EU-003).

(c) **Proper Selection of Process Catalyst**

The applicant can select a process catalyst that minimizes VOC emissions while maximizing the optimum catalytic conversion of CO to CO<sub>2</sub> in the high and low shift converters. The proper selection of a low VOC catalyst is a feasible control option for the CO<sub>2</sub> purification process (EU-003).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

Only one control technology has been identified; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
CO <sub>2</sub> Purification Process (EU-003) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	CO <sub>2</sub> Purification Process (EU-003)	2,646 ton ammonia per day	0.0558 lb/ton ammonia, 3 hr avg., 100% CO <sub>2</sub> venting	Proper Catalyst, Good Operation
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification Process (EU-004)	3,570 ton CO <sub>2</sub> per day	0.0558 lb/ton ammonia, 3 hr avg.; 1,022,000 ton ammonia/12 month rolling	Low VOC Catalyst
IA-0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,012 MT/day 3,313 ton/day	0.106 lb/ton ammonia, 3 run avg.; 51.2 ton/12 month rolling	Good Operational Practices

**RBLC Review**

The RBLC has two entries for nitrogenous fertilizer facilities of similar capacities. None of the entries uses a control device for VOC. This is due to extremely low VOC emissions in the exhaust stream. The stream is nearly pure CO<sub>2</sub>.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

The applicant has accepted top BACT. However, it is noted that this limit has not been demonstrated in practice and if unachievable, the BACT determination may require future revision.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the CO<sub>2</sub> purification process (EU-003):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Sale of the Captured CO<sub>2</sub>; and
- (c) Use CO<sub>2</sub> to Manufacture Urea (Good Operational Practices).

#### **Step 2: Eliminate Technologically Infeasible Options**

- (a) **Carbon Capture and Sequestration (CCS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. IDEM, OAQ determined that CCS was not a technologically feasible option for Midwest Fertilizer Corporation because the technology was not available or applicable.
- (b) **Sale of the Captured CO<sub>2</sub>**  
Sale of the Captured CO<sub>2</sub> was evaluated for the entire source under the BACT analysis for the reformer furnace. IDEM, OAQ determined the sale of CO<sub>2</sub> was not feasible for Midwest Fertilizer Corporation because the technology was not available or applicable. Midwest Fertilizer Corporation could not reasonably construct and operate a cross county transmission pipeline to an end purchaser of the collected CO<sub>2</sub>.
- (c) **Use of CO<sub>2</sub> to Manufacturer Urea**  
The Midwest Fertilizer Corporation CO<sub>2</sub> purification process is designed to use a portion of the CO<sub>2</sub> created in the CO<sub>2</sub> purification process to manufacture urea. Good operational practices to use as much CO<sub>2</sub> in the manufacture of urea is a feasible control strategy for the CO<sub>2</sub> purification process (EU-003).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only technologically feasible control technology. Therefore, a ranking is not necessary. The use of CO<sub>2</sub> to produce urea reduces or eliminates the need to purchase CO<sub>2</sub> for urea production. In addition, the use of CO<sub>2</sub> to produce urea decreases the total amount vented to the atmosphere from the CO<sub>2</sub> purification vent.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>CO<sub>2</sub> Purification Process (EU-003) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA -0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,012 MT/day 3,313 ton/day	CO <sub>2</sub> – 1.26 ton/ton ammonia; 30 day avg.; CO <sub>2</sub> e – 1,211,847 ton /12 month rolling	Good Operational Practices
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>CO<sub>2</sub> Purification (EU-003)</b>	<b>2,646 ton ammonia per day</b>	<b>CO<sub>2</sub> – 1.275 tons CO<sub>2</sub> per ton ammonia; 3 hr avg., 100% CO<sub>2</sub> venting; 1,232,475 ton CO<sub>2</sub> / 12 month rolling</b>	<b>Good Operational Practices, Usage Limit</b>
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification (EU-004)	3,570 tons/day CO <sub>2</sub>	CO <sub>2</sub> – 1.275 tons CO <sub>2</sub> per ton ammonia, 3 hr avg.; 1,022,000 tons ammonia /12 month rolling	Good Operational Practices

### **RBLC Review**

The RBLC has limited entries for processes similar to the CO<sub>2</sub> purification process. In fact, there are only two facilities and neither has been built. Add-on GHG control technologies were not used. Both the Iowa Fertilizer Company and the Ohio Valley Resources facilities use good operational practices to minimize GHG emissions. The emission rate proposed by the applicant is identical to the GHG BACT issued by IDEM, OAQ for the Ohio Valley Resources facility. While the Iowa Fertilizer Corporation is slightly lower, it should be noted the processes are not identical and IDEM, OAQ determined the difference is insignificant.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) The applicant proposes to use CO<sub>2</sub> from the CO<sub>2</sub> purification process for the manufacture of urea while the urea unit is operating.

The applicant selected BACT as the use of CO<sub>2</sub> emissions to produce urea only while the urea unit is operating. It is important to note that Midwest Fertilizer Corporation can only use CO<sub>2</sub> from this vent when the urea unit is operating. If the urea unit is shut down and Midwest Fertilizer

Corporation chooses to make only ammonia fertilizer then venting all of the CO<sub>2</sub> would be considered BACT in this operating scenario. Midwest Fertilizer Corporation will need the flexibility to produce only ammonia fertilizer depending on market conditions. CO<sub>2</sub> emissions will be limited to 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;
- (b) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (c) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

IDEM, OAQ selected an emission limit based on CO<sub>2</sub> instead of CO<sub>2</sub>e; because, the gases in the CO<sub>2</sub> purification vent are comprised of greater than 99% CO<sub>2</sub>.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the CO<sub>2</sub> Purification Process (EU-003)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the CO<sub>2</sub> purification process (EU-003) shall be as follows:

- (1) CO, VOC and CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;
- (2) CO emissions from the CO<sub>2</sub> purification process (EU-003) not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (3) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (4) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (5) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

<b>BACT Analysis – Startup Heater (EU-002)</b>
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**Emission Unit Description**

- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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:

- (a) Fuel Specifications – Clean Burning Fuel; and
- (b) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

- (a) **Cyclone**  
The theory of cyclone operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The startup heater is natural gas-fired with particulate matter emissions of less than 0.005 gr/cf. The cyclone is typically used as a pretreatment device for other control devices and are used in applications with waste gas loadings between 1 and 100 gr/scf. Because the waste loading of particulate in the startup heater is already below 1 gr/scf, this technology is not feasible for the startup heater (EU-002).



(b) **Wet Scrubber**

The theory of wet scrubber operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The wet scrubber can be utilized for fine particulate control with typical loadings between 0.1 and 50 gr/scf. Once again, this technology is not feasible for the startup heater (EU-002) because the waste loading of the exhaust stream is below the level of control achievable by the scrubber.

(c) **Electrostatic Precipitators (ESP)**

The theory of electrostatic precipitator operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The design inlet loadings for ESPs typically range from 0.5 to 50 gr/scf. Natural gas waste loadings for particulate are well below the reduction possible by an ESP. Therefore, this technology is not feasible for the startup heater (EU-002).

(d) **Fabric Filter Dust Collectors (Baghouses)**

Baghouses are commonly used where low levels of particulate matter removal is required. A typical baghouse is capable of an outlet design concentration of 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. The outlet design concentration of the startup heater exhaust is essentially the same as the outlet emission concentration of a baghouse. In addition, a particulate layer will be difficult to develop on the filter media because of the low pollutant loading. No appreciable emission reduction can be obtained by use of a baghouse on a natural gas combustion source. Therefore, this technology is not feasible for the startup heater (EU-002).

(e) **Fuel Specifications – Clean Burning Fuel**

Clean burning natural gas has a very low potential for generating PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Fuel specifications are a technically feasible control option for the startup heater (EU-002).

(f) **Good Combustion Practices / Combustion Controls**

Good combustion practices as well as operation and maintenance of the startup heater (EU-002) to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices are a technically feasible control option for the startup heater (EU-002).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the startup heater (EU-002).

(a) Fuel Specifications – Clean Burning Fuel

(b) Good Combustion Practices / Combustion Controls

The applicant selected all control measures; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Start Up Heater (EU-002) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.0024 lb/MMBtu, 3 run avg.; 0.01 ton/12 month rolling, each	Good combustion practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.; 18.14 MMCF/12 month rolling	Good design and combustion, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Heater (EU-010)	106.3 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.; 20.84 MMCF/12 month rolling	Good design and combustion, natural gas
LA-0231	Lake Charles Cogeneration	06/22/09	Methanator Startup Heater	56.90 MMBtu/hr	PM <sub>10</sub> - 0.42 lb/hr maximum	Good Design and Operation
TN-0153	Williams Refining & Marketing	04/03/02	No. 2 N/S ECU Heaters	166.5 MMBtu/hr	PM <sub>10</sub> - 0.005 lb/MMBtu (filterable)	None
TN-0153	Williams Refining & Marketing	04/03/02	WCR Heater	209.0 MMBtu/hr	PM <sub>10</sub> - 0.005 lb/MMBtu (filterable)	None

#### RBLC Review

The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) result from the combustion of natural gas. PM/PM<sub>10</sub>/PM<sub>2.5</sub> from the startup heater (EU-002) will result in a particulate concentration in the exhaust of 0.005 grains/dscf or less. This low concentration renders add-on controls infeasible. Generally add-on controls for PM, PM<sub>10</sub> and PM<sub>2.5</sub> are not applied to a combustion source firing only clean gaseous fuel. This is because the PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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.

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate control technologies for PM/ PM<sub>10</sub>/PM<sub>2.5</sub> emissions from natural gas-fired heaters are used. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate of a natural gas fired heater will be 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and 1.9 lb/MMCF for PM. The Williams Refining & Marketing process heaters have an emission limit of 0.005 lb/MMBtu but only includes filterable PM<sub>10</sub> and PM<sub>2.5</sub>. When condensable emissions are considered, the emission rate is identical to the emission rate proposed by the applicant. The Iowa Fertilizer Company emission rate is the lowest entry for a natural gas fired process heater.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The use of natural gas;
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively;
- (c) The startup heater shall not combust in excess of 18.14 MMCF of natural gas in a twelve consecutive month period, with compliance determined at the end of each month; and
- (d) Good heater design and good combustion practices.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM<sub>10</sub>, and PM<sub>2.5</sub>. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 1.9, 7.6 and 7.6 lb/MMCF for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

### **Step 5: Select BACT**

IDEM has established BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following NO<sub>x</sub> control technologies for the startup heater (EU-002):

- (a) Selective Catalytic Reduction (SCR)
- (b) Selective Non-Catalytic Reduction (SNCR)
- (c) Low NO<sub>x</sub> Burner (LNB)
- (d) Flue Gas Recirculation (FGR)
- (e) Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)
- (f) No Control

NO<sub>x</sub> add-on control technologies are discussed below:

### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Selective Catalytic Reduction (SCR)**  
The theory of operation of an SCR unit was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. SCR has been installed on process heaters and boilers for many years. Therefore, selective catalytic reduction (SCR) is a technologically feasible control option for the startup heater (EU-002).
- (b) **Selective Non-Catalytic Reduction (SNCR)**  
The theory of operation of an SNCR unit was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. SNCR requires the employment of an injection system that can accomplish thorough reagent / gas mixing within a narrow temperature range while accommodating temperature variation in the exhaust stream. This technology requires relatively stable steady-state operation within a narrow temperature range. Given the standby nature of this process heater, selective non-catalytic reduction is not a technically feasible control option for the startup heater (EU-002).
- (c) **Low NO<sub>x</sub> Burner (LNB)**  
The theory of operation of low NO<sub>x</sub> burners was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. NO<sub>x</sub> emission reductions can be realized using low NO<sub>x</sub> burners in natural gas-fired combustion sources. The use of low NO<sub>x</sub> burners is a feasible control option for the startup heater (EU-002).
- (d) **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 NO<sub>x</sub> production. Flue gas recirculation (FGR) can be a highly effective technique for lower NO<sub>x</sub> emissions from burners and it is 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 NO<sub>x</sub> emissions to a little as 25% of their normal levels. FGR lowers NO<sub>x</sub> emissions by: the cooler, relatively inert, recirculated flue gases act as a 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 NO<sub>x</sub> forming reactions of one of the needed ingredients. FGR has been used on natural gas-fired boilers and process heaters and it is a technically feasible control option for the startup heater (EU-002).

- (e) **Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)**  
Low NO<sub>x</sub> burners can be combined with flue gas recirculation to achieve an even higher level of control than each can provide individually. The combination of FGR and low NO<sub>x</sub> burners are a technologically feasible control option for the startup heater (EU-002).
- (f) **No Control Option**  
The no control option is where no add-on controls are proposed to control NO<sub>x</sub> from the startup heater (EU-002). This option is usually feasible in the case of emission units that have extremely low emissions or extremely low hours of operation that make the use of add-on controls impractical. The use of the no control option is a technically feasible control option for the startup heater (EU-002).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following control technologies are available for NO<sub>x</sub> control for the startup heater (EU-002). They are ranked in order of control efficiency:

- (a) Selective Catalytic Reduction (90% Control)
- (b) Low NO<sub>x</sub> Burners with Flue Gas Recirculation (55% to 60% Control)
- (c) Low NO<sub>x</sub> Burners (50% Control)
- (d) Flue Gas Recirculation (25% Control)
- (e) No Control Option (0% Control)

The applicant has selected a no control option as BACT. As such, a technical, environmental and economic analysis is normally performed. In this case, IDEM, OAQ is not requiring further analysis because this emission unit will only operate 200 hours a year and the use of add-on controls would be impractical.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b> <b>Startup Heater (EU-002) – NO<sub>x</sub></b>						
RBLCL ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.119 lb/MMBtu, 3 run avg.; 0.63 ton/12 month rolling	Good Combustion Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	183.70 lb/MMCF, 3 hr avg., 18.14 MMCF/12 month rolling	Good Design and Combustion, Natural Gas

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Startup Heater (EU-002) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Startup Heater (EU-010)	106.3 MMBtu/hr	183.70 lb/MMCF, 3 hr avg., 20.84 MMCF/12 month rolling	Good Design and Combustion, Natural Gas
LA-0244	Sasol N.A., Inc.	11/29/10	Natural Gas Charge Heater	87.3 MMBtu/hr	7.15 lb/hr, maximum	Low NO <sub>x</sub> Burners
LA-0244	Sasol, N.A., Inc.	11/29/10	Oil Heater	170 MMBtu/hr	19.69 lb/hr, maximum	Low NO <sub>x</sub> Burners
LA-0262	Cornerstone Chemical Company	05/03/12	Startup Heater	61 MMBtu/hr	10.15 lb/hr, maximum; 1.73 TPY maximum	Good Engineering Design

#### **RBLC Review**

The startup heater (EU-002) is intended to be used by the source for a maximum of 200 hours per year for plant startup. The limited amount of use of this heater makes the use of add-on controls impractical. The unrestricted potential to emit NO<sub>x</sub> of the startup heater is 48.62 TPY. The limited potential to emit based on 200 hours of operation is 1.11 TPY. NO<sub>x</sub> emissions from these units are best controlled by good combustion practices.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) NO<sub>x</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

The lowest emission rate indicated in the RBLC is 0.08 lb/MMBtu. Midwest Fertilizer Corporation is proposing an emission rate of 0.18 lb/MMBtu and an annual limit of 200 hours of operation. If the Midwest Fertilizer Corporation was to accept a BACT limit of 0.08 lb/MMBtu without a limit on the hours of operation, the startup heater would emit 32.41 tons of NO<sub>x</sub> per year. If the applicant's proposal is accepted, the startup heater would emit 1.67 tons of NO<sub>x</sub> per year. So while the emissions on an hourly rate are higher, the annual rate is much lower and represents a higher level of control.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) NO<sub>x</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

### **CO BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following CO control technologies for the startup heater (EU-002):

- (a) Regenerative Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

Each of the control technologies is discussed below.

### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Regenerative Thermal Oxidizer (RTO)**  
The theory of operation of the regenerative thermal oxidizer was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The use of an RTO is not a technologically feasible control option for the startup heater (EU-002). Thermal oxidation is not normally used to control CO in the exhaust streams of natural gas combustion. The combustion products have a low heating value that makes the use of a thermal oxidizer impractical.
- (b) **Catalytic Oxidation**  
The theory of catalytic oxidation was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for natural gas-fired combustion units because the fuel is low in sulfur with relatively low concentrations of other contaminants, such as metals. The use of catalytic oxidation is a technically feasible control option for the startup heater (EU-002).
- (c) **Flares**  
The theory of operation of flares was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The heating value of the startup heater's exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require significant addition of supplemental fuel. Therefore, a secondary impact of the use of a flare for this waste stream would be the creation of additional emissions from burning supplemental fuel, including NO<sub>x</sub>. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is a technically infeasible option for CO control from the startup heater (EU-002).

(d) **Combustion Control**

The theory of combustion control was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. 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 startup heater.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

- (a) Oxidation Catalyst – 75% destruction efficiency
- (b) Combustion Control

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Startup Heater (EU-002) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	0.0194 lb/MMBtu, 3 run avg.; 0.1 ton/12 month rolling	Good Combustion
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu, 7.4 TPY	Good Combustion
MD-0035	Dominion Cove Pt.	08/12/05	Vaporization Heater	88.4 MMBtu/hr	0.03 lb/MMBtu	Good Combustion, Good Operations, Natural Gas
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Startup Heater (EU-002)</b>	<b>92.5 MMBtu/hr</b>	<b>37.23 lb/MMCF, 3 hr avg. 18.14 MMCF/12 month rolling</b>	<b>Good Combustion, Good Operations, Good Design, Natural Gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Heater EU-010	106.3 MMBtu/hr	37.23 lb/MMCF, 3 hr avg.; 20.84 MMCF/12 month rolling	Good Combustion, Good Operations, Good Design, Natural Gas



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Startup Heater (EU-002) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
OK-0136	Conoco Phillips	02/09/09	Crude Heater	125 MMBtu/hr	5.0 lb/hr and 21.9 TPY, 365 day rolling; 0.04 lb/MMBtu	Ultra Low NOx Burners and Good Combustion
MN-0070	Minnesota Steel Industries	09/07/07	Process Heaters	606 MMBtu/hr	0.08 lb/MMBtu, 1 hr rolling; 50 lb/hr, 1 hr rolling	None

#### RBLC Review

A review of CO BACT analysis for natural gas-fired process heaters in the RBLC shows add-on control technology is not practical. CO emissions are controlled exclusively by good combustion practices and limits on the operation of the combustion unit. As noted earlier, catalytic oxidation is not a cost effective CO emission control system for the reformer furnace. Because of the lower utilization of the startup heater and lower CO emissions, it is even less cost-effective to use catalytic oxidation for the startup heater. In addition, the use of a thermal or catalytic oxidizer for CO control would require significant supplemental fuel resulting in additional CO emissions. The emission rate proposed by Midwest Fertilizer Corporation is identical to the recently issued Ohio Valley Resource permit. It is comparable to the Dominion Cove Pt. heater and only two entries are lower.

#### Applicant Proposal

The applicant proposed the following for BACT:

- The startup heater (EU-002) shall combust natural gas;
- CO emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

The applicant's proposal is consistent with or lower than a majority of the entries in the RBLC for CO emissions. Midwest Fertilizer Corporation's emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The next lowest entry in the RBLC for CO from a startup heater is 0.02 lb/MMBtu from the Williams Field Services Oil Heater in Wyoming. If Midwest Fertilizer Corporation accepted the lower emission rate without the limit on the hours of operation, the startup heater would emit 8.1 tons CO per year. If the applicant's proposal of 0.0365 lb/MMBtu with a 200 hour per year operational limit is accepted, the startup heater would emit 0.34 tons of CO per year. With 0.34 ton/year of CO emissions, add-on controls needed to achieve 0.02 lb CO/MMBtu is not cost effective. While the hourly emission rate would be lower at 0.02 lb CO/MMBtu, the applicant's proposal represents an overall lower annual emission rate and represents BACT for this unit.

**Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) CO emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

**VOC BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the Ammonia Catalyst Startup Heater (EU-002):

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Good Combustion Practices.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Thermal Oxidation**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. Generally, it is impractical for thermal oxidizers to reduce VOC emissions from a properly operated natural gas-fired combustion unit. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a feasible control technology for the startup heater (EU-002).

### **(b) Catalytic Oxidation**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. Much like the thermal oxidizer, a catalytic oxidizer uses high temperatures in the presence of a catalyst to combust VOC in the exhaust stream. This works for exhaust streams with significant organic content. The exhaust stream from the startup heater does not contain sufficient organic material to support combustion and a large amount of additional combustion fuel is required. The use of a catalytic oxidizer is not a technologically feasible control option for the startup heater (EU-002).

### **(c) Flares**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. The low heating value of the startup heater 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The VOC emissions created by this unit are due to natural gas combustion, additional natural gas would increase VOC emissions. The use of a flare is not a technically infeasible option for the startup heater (EU-002).

### **(d) Good Combustion Practices**

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 VOC 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 startup heater (EU-002).

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The only conventional VOC control technology that is technologically feasible for the startup heater (EU-002) is good combustion practices. A ranking is not necessary.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Ammonia Catalyst Startup Heater (EU-002) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	0.0014 lb/MMBtu, 3 run avg.; 0.01 ton / 12 month rolling	Good Combustion Practices
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Startup Heater (EU-002)</b>	<b>92.5 MMBtu/hr</b>	<b>5.5 lb/MMCF, 3 hr avg.; 18.14 MMCF/12 month rolling</b>	<b>Good Combustion, Good Design, Natural Gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Catalyst Startup Heater (EU-010)	106.3 MMBtu/hr	5.5 lb/MMCF, 3 hr avg. 20.84 MMCF/12 month rolling	Good Combustion Good Design Natural Gas
OH-0329	BP Products Husky Refining	08/07/09	Reformer Heater	519 MMBtu/hr	2.8 lb/hr; 12.28 ton/12 month rolling; 5.5 lb/MMCF	None
LA-0197	Conoco Phillips, Alliance	07/21/09	Gasoline Feed Heater	138.12 MMBtu/hr	0.74 lb/hr maximum, 2.72 TPY maximum	Good Combustion Good Engineering
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu 7.0 TPY	Good Combustion
OK-0134	Pryor Plant Chemical Company	02/23/09	Nitric Acid Preheaters	20 MMBtu/hr	0.11 lb/hr	Good Combustion
SC-0115	GP Clarendon LP	02/10/09	Backup Oil Heater	75 MMBtu/hr	0.39 lb/hr; 1.72 TPY	Good Combustion

#### **RBLC Review**

None of the process heater listed in the RBLC used an add-on control device for VOC control. VOC emissions were controlled by good combustion practice.

### **Applicant Proposal**

The applicant proposed the following as VOC BACT:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) VOC emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

The applicant's proposal is consistent with a majority of the entries in the RBLC and with recent BACT determinations from IDEM, OAQ. The emission limit proposed by Midwest Fertilizer is based on the AP-42 emission factor for natural gas combustion. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM, OAQ believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) VOC emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

## **Greenhouse Gas BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas control technologies for the startup heater (EU-002):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices; and
- (c) Low Carbon Fuel.

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ has evaluated each of the Step 1 technologies for the startup heater (EU-002) below:

- (a) **Carbon Capture and Sequestration (CSS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. The startup heater is used during plant startup to preheat the ammonia catalyst until a temperature is reached where the reaction is self-sustaining. The unit will operate for a maximum 200 hours per year for startups and maintenance. As was discussed in detail under the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology for the startup heater (EU-002).
- (b) **Good Design and Combustion Practices**  
The proper design, operation, and maintenance of the startup heater will ensure optimal operation and the minimization of greenhouse gas emissions. Operation of the heater can be controlled by the use of inlet air control sensors that limit excess air and result in optimal combustion. Good design and combustion practices are a technologically feasible control technology for the startup heater (EU-002).
- (c) **Low Carbon Fuel**  
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of low carbon fuel such as natural gas is a technologically feasible control option for the startup heater (EU-002).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has selected all technically feasible control options for the startup heater (EU-002). Therefore, there is no need to rank the control options.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Catalyst Startup Heater (EU-002) – Greenhouse Gases						
RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	CO <sub>2</sub> - 59.61 tons/MMCF, 3 hr avg., 18.14 MMCF/12 month rolling	Good Combustion, Good Design, Natural Gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Startup Heater (EU-010)	106.3 MMBtu/hr	CO <sub>2</sub> - 59.61 tons/MMCF, 3 hr avg. 20.84 MMCF/12 month rolling	Good Combustion, Good Design, Natural Gas
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, 3 run avg.; CH <sub>4</sub> -0.0023 lb/MMBtu, 3 run avg.; CO <sub>2</sub> e – 638 ton/12 month rolling; N <sub>2</sub> O – 0.0006 lb/MMBtu, 3 run average	Good Combustion

#### RBLC Review

Due to the intermittent operation of these startup heaters, add-on control devices are not practical. All similar units in the RBLC use a combination of low carbon fuel, proper design, good combustion practices and limits on the hours of operation.

#### Applicant Proposal

The applicant proposes the following for GHG BACT for the startup heater (EU-002):

- The startup heater (EU-002) shall combust natural gas.
- GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

The applicant has proposed top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas.
- (b) GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Startup Heater (EU-002)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the startup heater (EU-002) shall be as follows:

- (1) The startup heater (EU-002) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (3) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
- (5) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average;
- (6) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average;
- (7) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (8) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.



## **BACT Analysis – Front End Flare (EU-017)**

### **Emission Unit Description**

- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.

### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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:

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

#### **Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

- (a) **Flare design and good combustion practices**  
Flare design and operation are key elements in the emissions performance of flares. The front end flare (EU-017) 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 use of flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).
- (b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the front end flare (EU-017).
- (c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (a) Proper flare design and good combustion practices; and
- (b) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b>						
<b>Front End Flare (EU-017) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Front End Flare (EU-017)</b>	<b>4.0 MMBtu/hr</b>	<b>PM–0.0019 lb/MMBtu PM<sub>10/2.5</sub>–0.0075 lb/MMBtu, 3 hr average</b>	<b>Good combustion practice/flare design, flare minimization plan, nat gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	PM–0.0019 lb/MMBtu PM <sub>10/2.5</sub> –0.0075 lb/MMBtu, 3 hr average	Proper design and operation, low carbon fuel, flare minimization practices
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Smokeless Flare; Good Combustion; VE notations by Method 22
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

### **RBLC Review**

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42, Chapter 1.4 emission factor. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

### **Applicant Proposal**

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of Pm and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for front end flare (EU-017):

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the front end flare (EU-017):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the front end flare (EU-017).
- (b) **Process flaring minimization practices**  
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).
- (c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:
  - (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA Front End Flare (EU-017) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Front End Flare (EU-017)</b>	<b>4.0 MMBtu/hr</b>	<b>0.068 lb/MMBtu, pilot and 595.49 lb/hr venting, 3 hr average, Venting not to exceed 336 hr/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	0.068 lb/MMBtu, pilot and 595.49 lb/hr venting, venting not to exceed 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion

#### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (e) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.
- (f) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the front end flare (EU-017):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

#### **(a) Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).

#### **(b) Process flaring minimization practices**

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. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).

#### **(c) 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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA Front End Flare (EU-017) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Front End Flare (EU-017)</b>	<b>4.0 MMBtu/hr</b>	<b>0.37 lb/MMBtu, 3,240.16 lb/hr venting, based on 3 hour average, 336 hr venting/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	0.37 lb/MMBtu, pilot and 3,240.16 lb/hr, venting, 3 hr average, 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from process, no limit on pilot	None

#### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the front end flare (EU-017) shall be controlled by good combustion practices;
- (b) CO emissions from the front end flare (EU-017) shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.



**Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by the use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, while venting, based on a three-hour average.
- (f) Venting to the front end storage flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

**VOC BACT**

**Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the front end flare (EU-017):

- (a) Flare Design and Monitoring;
- (b) Process Flaring Minimization Practices; and
- (c) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).

### **(b) Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).

### **(c) 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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Front End Flare (EU-017) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	0.0054 lb/MMBtu, pilot and 47.26 lb/hr, venting 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare (EU-007)	37.741 MMBtu/hr	0.0054 lb/MMBtu, pilot and 47.26 lb/hr, venting 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

#### **RBLC Review**

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

#### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

- (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
- (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr during venting, based on a three-hour average.
- (f) Venting of emissions to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the front end flare (EU-017):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices;
- (c) Flare Minimization practices (FMP); and
- (d) Low Carbon Fuel for Pilot and Sweep Gas.

#### **Step 2: Eliminate Technically Infeasible Options**

##### **(a) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. Greenhouse gas emissions from the front end flare (EU-017) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the front end flare (EU-017).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the front end flare (EU-017).

(d) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Front End Flare (EU-017) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Front End Flare (EU-017)</b>	<b>4.0 MMBtu/hr</b>	<b>CO<sub>2</sub> – 116.89 lb/MMBtu, pilot and 511.81 ton/hr, venting, 3 hr average; 336 hr venting/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
<b>T147-32322-00062</b>	<b>Ohio Valley Resources</b>	<b>09/25/13</b>	<b>Front End Process Flare EU-007</b>	<b>37.741 MMBtu/hr</b>	<b>CO<sub>2</sub> – 116.89 lb/MMBtu, pilot and 511.81 ton/hr, 3 hr average; 336 hr venting/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Front End Flare (EU-017) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr and 4,852 TPY; CH <sub>4</sub> -0.06 lb/hr and 0.08 TPY; N <sub>2</sub> O-0.05 lb/hr and 0.08 TPY	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY maximum	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY Maximum	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### **RBLC Review**

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

#### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (e) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, during venting, based on a three-hour average.
- (f) Venting emissions to front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Front End Flare (EU-017)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the front end flare (EU-017) shall be as follows:

- (1) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (2) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events.
  - (A) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;

- (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
    - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
    - (B) Flares shall be operated with a flame present at all times; and
    - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
  - (5) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
  - (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.
  - (7) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
  - (8) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.
  - (9) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
  - (10) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, during venting, based on a three-hour average.
  - (11) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
  - (12) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr, during venting, based on a three-hour average.
  - (13) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
  - (14) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, while venting, based on a three-hour average.



<b>BACT Analysis – Back End Flare (EU-018)</b>
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**Emission Unit Description**

- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions, there are limited process and/or add-on control alternatives available. Based on a review of the RBL, as well as other permits and sources, the list of potential control and process alternatives includes the following:

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

**Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

(a) **Flare design and good combustion practices**

Flare design and operation are key elements in the emissions performance of flares. The back end flare (EU-018) 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 use of flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).

(b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the back end flare (EU-018).

(c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (a) Proper flare design and good combustion practices; and
- (b) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Back End Flare (EU-018) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Back End Flare (EU-018)</b>	<b>4.0 MMBtu/hr</b>	<b>PM–0.0019 lb/MMBtu PM<sub>10/2.5</sub>–0.0075 lb/MMBtu</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare EU-006	38.264 MMBtu/hr	PM–0.0019 lb/MMBtu PM <sub>10/2.5</sub> –0.0075 lb/MMBtu	Good combustion practice/flare design, flare minimization plan, natural gas
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Smokeless, good combustion, VE by method 22
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

### **RBLC Review**

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42, Chapter 1.4 emission factor. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

### **Applicant Proposal**

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for back end flare (EU-018):

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the back end flare (EU-018):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

(a) **Flare design and good combustion practices**

Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the back end flare (EU-018).

(b) **Process flaring minimization practices**

Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA Back End Flare (EU-018) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Back End Flare (EU-018)</b>	<b>4.0 MMBtu/hr</b>	<b>0.068 lb/MMBtu pilot, and 624.94 lb/hr venting, 3 hr average; 336 hr venting/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Flare EU-006	38.264 MMBtu/hr	0.068 lb/MMBtu, pilot and 624.94 lb/hr venting, 3 hr average; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion and Meet 40 CFR 60.18
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

#### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.

- (e) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the back end flare (EU-018):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

#### **(a) Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).

#### **(b) Process flaring minimization practices**

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. The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).

#### **(c) 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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Back End Flare (EU-018) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Back End Flare (EU-018)</b>	<b>4.0 MMBtu/hr</b>	<b>0.37 lb/MMBtu pilot and 804.76 lb/hr venting, 3 hr avg.; 336 hr venting/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare EU-006	38.264 MMBtu/hr	0.37 lb/MMBtu, pilot and 804.76 lb/hr, venting, 3 hr avg.; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion and Meet 40 CFR 60.18



### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the back end flare (EU-018) shall be controlled by good combustion practices;
- (b) CO emissions shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by the use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.

- (e) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the back end flare (EU-018):

- (a) Flare Design and Monitoring;
- (b) Process Flaring Minimization Practices; and
- (c) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

#### **Step 2: Eliminate Technically Infeasible Options**

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Back End Flare (EU-018) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Back End Flare (EU-018)</b>	<b>4.0 MMBtu/hr</b>	<b>0.0054 lb/MMBtu, pilot and 11.73 lb/hr venting, 3 hr avg. and 336 hr/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare (EU-006)	38.264 MMBtu/hr	0.0054 lb/MMBtu, pilot and 11.73 lb/hr, venting, 3 hr avg. and 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No Limits	Comply with 40 CFR 63, Subpart A

#### **RBLC Review**

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

**Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

**Greenhouse Gas BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the back end flare (EU-018):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices;
- (c) Flare Minimization practices (FMP); and
- (d) Low Carbon Fuel for Pilot and Sweep Gas.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT for the reformer furnace. Greenhouse gas emissions from the back end flare (EU-018) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the back end flare (EU-018).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the back end flare (EU-018).

(d) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas is a feasible control option.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Back End Flare (EU-018) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Back End Flare (EU-018)	4.0 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 127.12 ton/hr venting, 3 hr average and 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Flare Process Flare EU-006	38.264 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 127.12 ton/hr, venting	Good combustion practice/flare design, flare minimization plan, natural gas
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr and 4,852 ton/12 month rolling; CH <sub>4</sub> -0.06 lb/hr and 0.08 ton/12 month rolling; N <sub>2</sub> O-0.05 lb/hr and 0.08 ton/12 month rolling.	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY, maximum	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY, maximum	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### Applicant Proposal

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (e) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Back End Flare (EU-018)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the back end flare (EU-018) shall be as follows:

- (1) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (2) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) PM emissions from the back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
- (7) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.



- (8) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.
- (9) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.
- (11) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (12) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.
- (13) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (14) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.

<b>BACT Analysis – Urea Granulation Unit (EU-008)</b>
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**Emission Unit Description**

- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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**

The theory of operation of a cyclone was discussed in detail in the particulate BACT for the reformer and will not be repeated here. Granulated urea is created in the granulation unit by spraying a heated liquid into a fluidized bed containing fine granules. The urea coats the particles until they reach the desired diameter. The hot urea granules are sticky until completely cooled. Cyclones rely on particulate matter to fall out of the gas stream when they impact the wall of the control device. Because the granules are sticky, they will collect on the walls of the cyclone instead of falling into the collection hopper. This will cause the unit to foul on a frequent basis. Therefore, a cyclone is not a feasible control technology for this waste gas stream.

### **(b) Wet Scrubbers**

The urea granules created in the granulation unit are hygroscopic. They tend to attract water in the air. This physical property makes wet scrubbers an ideal control device. Therefore, wet scrubbing is a technologically feasible control technology.

### **(c) Electrostatic Precipitators (ESP)**

Electrostatic precipitators impart a negative electric charge to particulate in the waste gas stream and a positive charge to the collector plates. The difference in electrical charge results in particulate being attracted to the collection plates. Collected particulate matter is typically removed during a cleaning cycle by rapping. A process whereby a vibration is used to dislodge the charged particles. Because of the physical characteristics of this waste gas stream, the charged particles will become stuck to the walls of the control device. This will reduce collection efficiency and will result in excessive maintenance problems. The use of an electrostatic precipitator is not a technologically feasible control technology for this application.

### **(d) Fabric Filter Dust Collectors (Baghouses)**

Baghouses use a fabric filter to physically separate particulate from the waste gas stream. This method of operation is not compatible with the sticky physical properties of the hot urea granule. Fouling will cause excessive maintenance problems. Therefore, this is not a technologically feasible control technology for this application.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only technologically feasible control technology for the urea granulation unit (EU-008). Therefore, a ranking is not needed.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Urea Granulator (EU-008) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0106	CF Industries Nitrogen, LLC	07/18/13	Urea Granulator	176.46 ton urea/hr (4,235 ton/day)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> 0.11 lb /ton urea, 3 run avg. and 85.7 ton/12 month rolling	Wet Scrubber Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Urea Granulator (EU-008)	1,587 tons urea/day	PM/PM <sub>10</sub> , PM <sub>2.5</sub> - 0.163 lb/ton urea	Wet Scrubber 90% Control
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granulator	1,500 metric ton urea/day	0.10 kg PM/MT 0.10 kg PM <sub>10</sub> /MT 0.025 kg PM <sub>2.5</sub> /MT, 3 run avg.; PM/PM <sub>10</sub> – 60.4 ton/12 month rolling; PM <sub>2.5</sub> – 15.1 ton/12 month rolling	Wet Scrubber
OK-0124	Koch Nitrogen Company	04/09/09	Urea Granulator	1,550 ton urea/day	6.6 lb/hr PM <sub>10</sub>	Wet Scrubber 90% Control

#### RBLC Review

Urea granulation units are typically controlled by a wet scrubber. This is due to the physical characteristics of the hot urea granules. The only facility in the above table that has been constructed is the Koch Nitrogen Company facility near Enid, Oklahoma. A stack test of the urea granulator indicates PM/PM<sub>10</sub> emissions from the unit are approximately 0.3 lb/ton. The applicant is proposing an emission rate of 0.163 lb/ton PM, PM<sub>10</sub> and PM<sub>2.5</sub>, each. This is the lowest emission rate of any facility which has been constructed and demonstrated in practice.

#### Applicant Proposal

The applicant proposed the following for BACT:

- (a) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall not exceed 0.163 lb per ton granules, each.

The applicant's proposal is significantly below the only RBLC entry for a facility that has been constructed and stack tested. As such, IDEM, OAQ accepts the applicant's proposal as BACT for the urea granulator.

#### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for the urea granulation unit (EU-008) as:

- (a) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall not exceed 0.163 lb per ton granules, each, based on a three-hour average.

#### **NO<sub>x</sub>, CO and GHG PSD Applicability**

The urea granulation unit (EU-008) does not have the potential to emit NO<sub>x</sub>, CO, and GHG. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea granulation unit for these pollutants and a BACT analysis is not required for these pollutants.

#### **VOC PSD Applicability**

The urea granulation unit (EU-008) has a potential to emit VOC of 0.32 tons per year. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Urea Granulation Unit (EU-008)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granulator (EU-008) shall be as follows:

- (1) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall each not exceed 0.163 lb per ton granules, based on a three-hour average.

<b>BACT Analysis – Urea Granule Storage (EU-024)</b>
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#### **Emission Unit Description**

- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.

#### **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

#### **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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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.

(a) **Cyclones**

Cyclones are primarily used to control particulate matter (PM) with an aerodynamic diameter of 10 microns and greater. They are also used as pre-cleaners for other control devices and efficiently treat waste gas streams with high pollutant loadings. Emissions from the urea granule storage warehouse (EU-24) will contain significant amounts of fine particulate at a low grain loading. Therefore, a cyclone is not a technically feasible control device for this application.

(b) **Wet Scrubber**

Wet scrubbers are typically not used for fine particulate control due to the high liquid to gas ratios. They are more expensive to operate when compared to a baghouse and result in a waste liquid stream that may need special treatment. The wet scrubber can achieve collection efficiencies from 70% to 99% depending on the physical characteristics of the waste gas stream. The wet scrubber is a technically feasible control device for this application.

(c) **Electrostatic Precipitator**

Electrostatic precipitators are capable of removing particulate matter in the 2.5 micron range. Approximately 80% of all ESPs in the United States are used in the electric utility industry. This is not a common technology in the fertilizer production industry. This is due to the high capital and maintenance costs. Most modern ESPs can achieve collection efficiencies of 99% to 99.9%, while collection efficiencies of older units may be as low as 90%. Generally, ESPs are not competitive to baghouses for emission units with low pollutant loading and low gas flow rates. The ESP is not a technologically feasible control technology due to the operating characteristics of this waste gas stream.

(d) **Fabric Filters Dust Collectors (Baghouse)**

Baghouses have the capability to treat waste gas streams with particulate matter in the 2.5 micron range. Newer baghouse designs can achieve 99 to 99.9% control of particulate, while older units operate at 95% to 99.9% control. They are commonly used to control particulate emissions from the cement industry, coal cleaning, and quarry operations and are a technologically feasible control technology for the urea granule storage warehouse (EU-024).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the urea granule storage warehouse (EU-024):

- (a) Fabric Filter Dust Collectors (Baghouse) – 95% to 99.9% control
- (b) Wet Scrubber – 90% to 99.9%

The applicant has accepted a baghouse for control of the urea granule storage warehouse.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Urea Granule Storage Warehouse (EU-024) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Urea Granule Storage Warehouse (EU-024)</b>	<b>1,587 ton urea/day</b>	<b>PM, PM<sub>10</sub>/PM<sub>2.5</sub> 0.17 lb/hr 3 hr average</b>	<b>Baghouse</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granule Transfer	1,500 MT urea/day	PM - 0.005 gr/dscf PM <sub>10</sub> /PM <sub>2.5</sub> - 0.0013 gr/dscf, average 3 tests	Bin Vent Filter

#### **RBLC Review**

There is a single RBLC entry for controlling particulate matter emissions from urea granule storage warehouses. The Iowa Fertilizer Company (IFC) has the only granulated urea storage area listed in the RBLC. Particulate BACT IFC was based on an outlet grain loading of the baghouse controlling emissions. The baghouse was designed to control PM and PM<sub>10</sub> emissions to 0.005 gr/dscf. Midwest Fertilizer Corporation will control emissions to a lower level of 0.003 gr/dscf. The applicant will control PM<sub>2.5</sub> emissions to 0.003 gr/dscf. IFC proposed a lower emission rate of 0.0013 gr/scf for PM<sub>2.5</sub>. However, it is not clear that a baghouse collecting this material can routinely achieve a grain loading of 0.0013 gr/scf. Until tested and proven in practice, a grain loading of 0.003 gr/dscf represents the lowest level of PM<sub>2.5</sub> removal.

#### **Applicant Proposal**

The applicant has proposed the following for BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall not exceed 0.17 lb/hr, based on a three-hour average.

#### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for the urea granule storage warehouse (EU-024):

- (a) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall not exceed 0.17 lb/hr, based on a three-hour average.

#### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The urea granule storage warehouse (EU-024) does not have the potential to emit NO<sub>x</sub>, CO, VOC, and GHG. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea granule storage warehouse (EU-024) for these pollutants and BACT analyses are not required.

**Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Urea Granule Storage Warehouse (EU-024)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granule storage warehouse (EU-024) shall be as follows:

- (1) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall each not exceed 0.17 lb/hr, based on a three-hour average.

**BACT Analysis –Nitric Acid Plant (EU-009)**

**Emission Unit Description**

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit particulate. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the nitric acid plant (EU-009) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction
- (b) Non-Selective Catalytic Reduction (NSCR)
- (c) Selective Catalytic Reduction (SCR)

These add-on control technologies and combustion control approaches are discussed below.

- (a) **Selective Catalytic Reduction (SCR)**  
SCR is a system capable of reducing both NO<sub>x</sub> and N<sub>2</sub>O emissions from waste industrial gases. This is a feasible control technology for the nitric acid plant (EU-009).
- (b) **Non-Selective Catalytic Reduction (NSCR)**  
Nonselective catalytic reduction (NSCR) is an add-on NO<sub>x</sub> control technology for exhaust streams with low oxygen content. Nonselective catalytic reduction uses a catalyst reaction to reduce NO<sub>x</sub>, CO and hydrocarbons to water, carbon dioxide, and nitrogen. The system works by injecting a reducing agent into the exhaust stream prior to the catalytic reactor to reduce NO<sub>x</sub>. The control efficiency achieved ranges from 80% to 90%. Operating temperatures range from 700 F to 1,200 F and the oxygen concentration must be below 4%. This is a technologically feasible control technology for the nitric acid plant (EU-009).

(c) **Hydrogen Peroxide Injection**

Hydrogen peroxide injection was identified in the RBLC for the Kennewick Fertilizer Operation in the State of Washington. The project was granted an innovative control waiver under 40 CFR 52.21(v). After construction and operation, the BACT limit was reassessed to be 0.6 lb NO<sub>x</sub> / ton acid. This emission rate is greater than the emission limitation required by 40 CFR 60, Subpart Ga and no other facility is using this technology. This is not a feasible control technology for the nitric acid plant (EU-009).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the remaining control technologies in order of their NO<sub>x</sub> control efficiency and listed them below:

(a) Selective Catalytic Reduction – 95% control

(b) Non-Selective Catalytic Reduction (SNCR) – 93% control

The applicant has accepted top BACT.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Nitric Acid Plant (EU-009) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.064 lb/ton acid, 30 day average	SCR
T147-32322-00062	Ohio Valley Resources	09/25/13	Nitric Acid Units EU-001A EU-001B	630 tons/day, each	0.5 lb/ton nitric acid, 30 day average	SCR
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,905 MT/day	5 ppmv, 30 day rolling and 30 TPY, 12 month rolling	De-NO <sub>x</sub> System
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 7 Nitric Acid Plant	76,300 TPY Nitric Acid	0.524 lb/ton nitric acid; 27 ton/12 month rolling	SCR, 98% Control
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 9 Nitric Acid Plant	270,000 TPY Nitric Acid	0.6 lb/ton acid, 400 lb/day, 47 ton/12 month rolling	Hydrogen Peroxide Injection, 98% Control



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Nitric Acid Plant (EU-009) – NO <sub>x</sub>						
RBL ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
GA-0109	PCS Nitrogen Fertilizer – Augusta Plant	05/10/05	Nitric Acid Plant	Unspecified	3 lb/ton 100% nitric acid 297 tons/yr	NSCR Combustor, 93% Control
OK-0135	Pryor Plant Chemical Company	02/23/09	Nitric Acid Plant #1	8.3 lb/hr	1.6 lb/ton annual, 3 lb/ton for a 7 day maximum, 58.2 TPY NO <sub>x</sub>	Extended Absorption with NSCR

#### **RBL Review**

Nitric acid production units have been successfully controlled with SCR and NSCR. NO<sub>x</sub> emission rates from existing BACT determinations range from a high of 3.0 lb/ton to 0.5 lb/ton. The control efficiencies of the control technology are not directly comparable because the individual process designs result in a wide range of NO<sub>x</sub> generation rates. The best comparison is the emission rate per unit of production.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.

The applicant has accepted top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the nitric acid plants (EU-009) as:

- NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.

### **CO PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit CO. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for CO and a BACT analysis is not required.

### **VOC PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit VOC. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for VOC and a BACT analysis is not required.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

The following GHG control technologies apply to the Nitric Acid Units (EU-001A and EU-001B):

- (1) Primary Controls – Suppression of N<sub>2</sub>O formation
- (2) Secondary Controls – Reduction of N<sub>2</sub>O after formation
- (3) Tertiary Controls – Reduction of N<sub>2</sub>O using catalytic control
- (4) Plant Energy Efficiency Considerations

#### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Primary Controls – Suppression of N<sub>2</sub>O formation**  
Primary controls refer to the modifications made to the catalyst and reaction conditions in the oxidation step to reduce the amount of N<sub>2</sub>O formed. Types of primary controls include extension of the ammonia oxidation reactor. The extended reactor includes an extra chamber free of catalyst between the catalyst and the heat exchangers, allowing additional residence time. Additional primary controls include modification to the oxidation catalyst. The use of primary controls would be considered an inherently lower emitting design. The use of primary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (b) **Secondary Controls – Reduction of N<sub>2</sub>O after formation**  
Secondary control refer to reductions in N<sub>2</sub>O through the use of an additional catalyst, immediately after the oxidation step in the ammonia burner, in which N<sub>2</sub>O is decomposed into nitrogen and oxygen. The use of secondary controls would be an add-on control technology. The use of secondary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (c) **Tertiary Controls – Reduction of N<sub>2</sub>O using catalytic control**  
Tertiary controls refer to reduction in N<sub>2</sub>O through catalytic reduction or decomposition after formation in the oxidation step. The catalyst can be placed either before or after the expander. The two types of catalyst used are non-selective catalytic reduction (NSCR) and catalytic conversion. The NSCR system converts N<sub>2</sub>O with some sort of fuel over a catalyst to produce nitrogen and water. The catalytic conversion process does not require any added fuels or reagents to decompose N<sub>2</sub>O to nitrogen and oxygen. There are several tertiary control systems capable of reducing both NO<sub>x</sub> and N<sub>2</sub>O from waste industrial gases. The Uhde EnviNOx System is one of these patented tertiary control systems. The use of tertiary controls would be capable of producing good results and is technically feasible.

(d) **Plant Energy Efficiency Considerations**

Plant energy efficiency considerations include process integration and heat recovery for steam production. The exothermic nature of the reactions means the nitric acid units are net exporters of energy. Therefore, careful consideration should be given to recovering as much of this thermal energy as possible to reduce the overall energy input to the plant. When energy inputs are reduced, greenhouse gas emissions are reduced. The use of plant energy efficiency considerations is a technically feasible control option for the Nitric Acid Units (EU-001A and EU-001B).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has reviewed the information submitted in support of this BACT determination and has ranked the remaining control options as shown below:

- (1) Tertiary Control (98% reduction, vendor guarantee)
- (2) Secondary Control (70% to 90% reduction)
- (3) Primary Control (30% to 85% reduction)
- (4) Plant Efficiency Considerations

A tertiary control system has been selected by the applicant. Therefore, no other analyses are required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Nitric Acid Plants (EU-009) – Greenhouse Gases</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.613 lb N <sub>2</sub> O/ton acid, 3 hr avg., 100% by weight acid equivalent solution	Tertiary Controls
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,700 MT/day	N <sub>2</sub> O - 30 ppmv, avg. 3 tests; CO <sub>2</sub> e - 44,991 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests	N <sub>2</sub> O Uhde De-N <sub>2</sub> O System CO <sub>2</sub> e - 29,543 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests
T147-32322-00062	Ohio Valley Resources	09/25/13	Nitric Acid Plants (EU-001A/B)	630 tons per day, each	1.05 lb N <sub>2</sub> O per ton nitric acid, 3 hr. avg.	Tertiary Controls

### **RBLC Review**

The RBLC contains two entries for nitric acid units in the fertilizer industry. The Iowa Fertilizer Company and Ohio Valley Resources both use a proprietary control technology for N<sub>2</sub>O control. These systems are designed to work with a paired nitric acid reactor. Midwest Fertilizer Corporation is using a tertiary control system using a catalytic reactor to control N<sub>2</sub>O emissions from the Nitric Acid Plant. When all three nitric acid plants are compared on emissions calculated using 100% by weight nitric acid equivalent solution as the production variable, IFC will emit 0.7 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. MFC will emit 0.613 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. OVR will emit 1.05 lb N<sub>2</sub>O per ton of 100% by weight nitric acid equivalent solution produced. The OVR permit limit applies at all times while the IFC and MFC limits exclude periods of startup, shutdown and malfunction. MFC has proposed the lowest N<sub>2</sub>O emission rate in the RBLC.

### **Applicant Proposal**

The applicant proposed the use of a catalytic reactor to achieve a 95% reduction in N<sub>2</sub>O at an emission rate of 0.613 lb N<sub>2</sub>O per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature. This is top BACT. The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.

The applicant provided information as part of the application indicating excess N<sub>2</sub>O emissions during startup and shutdown events from the nitric acid plant are less than two (2) tons per year and IDEM considers these emissions negligible. As such, IDEM, OAQ concurs with the use of work practice standards during startup, shutdown and malfunction (SSM) events.

### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the nitric acid plant (EU-009) as:

- (a) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled at all times by a catalytic reactor, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (b) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, with the production being expressed as 100 percent nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) During periods of startup, shutdown, and malfunction, N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:
  - (1) **Startup:**  
Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric

acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.

(2) **Shutdown:**

Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.

(3) **Malfunctions:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

IDEM, OAQ selected an emission limit based on N<sub>2</sub>O instead of CO<sub>2</sub>e because the only GHG reduced by the emission control system is N<sub>2</sub>O. The limit, therefore, requires a high level of performance in reducing the only GHG that can be controlled by the emission control system. N<sub>2</sub>O emissions comprise 95% of the pre-control CO<sub>2</sub>e emitted by the nitric acid stacks. The system does not reduce emissions of any other GHGs. CO<sub>2</sub> is present in nitric acid plant stack: it originates in the compressed air that is used as part of the nitric acid manufacturing process and a minor amount is generated when natural gas is used for N<sub>2</sub>O conversion.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Nitric Acid Plant (EU-009)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:

- (1) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton nitric acid, with the production being expressed as 100 percent nitric acid, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (2) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (3) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a catalytic reactor at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and

- (4) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, with the production being expressed as 100 percent nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (5) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> and N<sub>2</sub>O emissions shall be controlled by the use of good operational practices as described below:
  - (a) **Startup:**

Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and N<sub>2</sub>O & NO<sub>x</sub> reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.
  - (b) **Shutdown:**

Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.
  - (c) **Malfunctions:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

<b>BACT Analysis – Natural Gas Combustion Turbines (EU-013A and EU-013B)</b>
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**Emission Unit Description**

- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively.  
[40 CFR 60, Subpart KKKK]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Add-On Controls;
- (b) Fuel Specifications; and
- (c) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

(a) **Add-on Controls**

Add-on controls for particulate control from low sulfur natural gas-fired open-simple cycle combustion turbines with heat recovery includes wet scrubbers, fabric filter baghouse, electrostatic precipitator, and cyclones. None of these technologies is feasible for the combustion turbines because the particulate loading is already below the removal capabilities of these control devices. Therefore, add-on controls are not a feasible control strategy for the natural gas-fired combustion turbines.

(b) **Fuel Specifications**

Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate matter emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such, fuel specifications are the primary method of particulate matter control and are a feasible control technology for the combustion turbines.

(c) **Good Combustion Practices**

Good combustion practices as well as operation and maintenance of the combustion turbines to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the open-simple cycle combustion turbines with heat recovery (EU-013A/B).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control options. Therefore a ranking is not necessary.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – PM, PM<sub>10</sub> and PM<sub>2.5</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)</b>	<b><u>Each Unit</u> 283 MMBtu/hr 22.5 MW</b>	<b><u>PM</u> 0.0019 lb/MMBtu, 3 hr avg.  <u>PM<sub>10</sub> and PM<sub>2.5</sub></u> 0.0076 lb/MMBtu, 3 hr avg.</b>	<b>Natural Gas and Good Combustion Practices</b>
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	<u>Each Unit</u> 80 MW	<u>PM</u> 10.8 lb/hr	Unknown
WY-0070	Black Hills Power, Inc.	08/27/12	Two Natural Gas Combined Cycle Turbines	<u>Each Unit</u> 40 MW	<u>PM</u> 4.0 lb/hr 3-hr avg. and 17.5 ton each calendar year	Good Combustion Practices
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	<u>Each Unit</u> 30 MW	<u>PM<sub>10</sub></u> 2.11 lb/hr, maximum and 8.5 TPY maximum	Natural Gas and Good Combustion
VA-0319	Gateway Green Energy	05/02/13	Two Combined Cycle Combustion Turbines	<u>Each Unit</u> 80 MW	<u>PM<sub>10</sub> and PM<sub>2.5</sub></u> 5.0 lb/hr 3-hr avg.	Good Combustion Practices, clean burning fuel
LA-0256	Westlake Vinyls Company	04/03/12	Three Cogeneration Combustion Turbines	<u>Each Unit</u> 50 MW	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 3.72 lb/hr, maximum	Natural Gas and Good Combustion Practice
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two 35 MW Gas Turbines with HRSG	<u>Each Unit</u> 35 MW	<u>PM<sub>10</sub></u> 10.03 lb/hr 71.32 TPY	Natural Gas and Combustion Control



### **RBLC Review**

None of the RBLC entries proposed add-on controls for particulate matter. In all cases, good combustion practices was used to limit particulate matter emissions. Emissions from combustion turbines can vary significantly depending on the operating points selected to establish the BACT limit. This variation explains the difference in emission rates for similar units. The applicant has proposed the lowest emission level presented in the RBLC.

### **Applicant Proposal**

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery shall be controlled by the use of good combustion practices and proper design at all times the units are in operation;
- (b) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (c) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.0019 lb/MMBtu; and
- (d) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery shall be controlled by the use of good combustion practices and proper design at all times the units are in operation;
- (b) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (c) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average; and
- (d) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Good Combustion Practices;
- (b) Fuel Specification;
- (c) Selective Catalytic Reduction (SCR); and
- (d) Catalytic Oxidation.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Good Combustion Practices**

NO<sub>x</sub> is one of the primary pollutants created by natural gas combustion in an open-simple cycle combustion turbine. In addition, emissions from combustion turbines are highly dependent on the operating load on the turbine. Turbines are designed to achieve maximum efficiency at peak load and controlling emissions over all loads levels is extremely difficult.

NO<sub>x</sub> is a mixture of NO and NO<sub>2</sub> in a variable composition, that is formed by three mechanisms. Thermal NO<sub>x</sub> occurs by the fixation of atmospheric oxygen and nitrogen, which occurs at high combustion temperatures. A second method of NO<sub>x</sub> formation is prompt NO<sub>x</sub>. Prompt NO<sub>x</sub> forms from early combustion reaction of nitrogen and hydrocarbon radicals from the fuel. The final method of NO<sub>x</sub> formation is fuel-bound NO<sub>x</sub>. Fuel-bound NO<sub>x</sub> can occur when the fuel contains significant amounts of nitrogen. Natural gas has negligible amounts of nitrogen. Of the three methods, the most prevalent method of NO<sub>x</sub> formation is thermal NO<sub>x</sub>. Thermal NO<sub>x</sub> is controlled in a combustion turbine by maintaining a constant fuel-to-air ratio that maintains the flame temperature below the stoichiometric adiabatic temperature. Most new combustion turbines use lean pre-mixed combustion systems referred to as dry low NO<sub>x</sub> combustion that operates in a tightly controlled fuel-to-air mixture that results in a modest peak flame temperature. Good operational practices are a feasible control technology for the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B).

### **(b) Fuel Specification**

Selection of a fuel with negligible amounts of nitrogen will reduce fuel-bound NO<sub>x</sub> and will result in modest reductions in NO<sub>x</sub> emissions. Selection of a clean burning fossil fuel such as natural gas will minimize fuel-bound NO<sub>x</sub>. Fuel specification is a feasible control technology for the natural gas-fired combustion turbines.

### **(c) Selective Catalytic Reduction (SCR)**

The primary post-combustion NO<sub>x</sub> control method in use today is selective catalytic reduction (SCR). SCR units inject ammonia into the flue gas and reacts with NO<sub>x</sub> in the presence of a catalyst to produce nitrogen and water vapor. The ammonia is normally injected in the heat recovery steam generator where the temperature of the exhaust generally matches the activation temperature of the catalyst. Low temperature installations are available with operating temperatures in the 300 °F to 400 °F range. High temperature systems are available in 800 °F to 1,100 °F range. 80% to 90% reductions in NO<sub>x</sub> are typical with SCR systems.

SCR systems are expensive and can significantly impact the feasibility of a project using smaller gas turbines. SCR units are also subject to ammonia "slip," where unreacted ammonia escapes the process and create nuisance problems. Selective Catalytic Reduction (SCR) is a feasible control option for the combustion turbines.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the control effectiveness of all remaining control technologies:

- (a) Selective Catalytic Reduction (SCR) – 80% to 90% control
- (b) Good Combustion Practices – less than 80% control
- (c) Fuel Specification – minimal reduction

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW	2 ppmvd @ 15% O <sub>2</sub> 1 hr avg.	SCR
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW, each	2 ppmvd @ 15%, 24-hr rolling	SCR
WY-0061	Black Hills Corporation – Neil Simpson Two	05/10/04	Combined Cycle Combustion Turbine	40 MW	2.5 ppmv @ 15%, 24-hr rolling 4.7 lb/hr	Dry Low NO <sub>x</sub> Combustors and SCR
DE-0023	NRG Energy Center Dover	06/05/13	Gas Turbine with HRSG	One 655 MMBtu/hr (70 MW)	5.76 lb/hr 1 hr avg.; 2.5 ppm @ 15% O <sub>2</sub> 1 hr avg.	SCR
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	3 ppmv @ 15% O <sub>2</sub> , 1 hr avg., 4.6 lb/hr, 30 day rolling, 25.5 TPY	SCR
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	80 MW	3 ppmv @ 15%, 24-hr avg.	Low NO <sub>x</sub> Combustors and SCR
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two Gas Turbines with HRSG and duct burners	35 MW, 312 MMBtu/hr, each	11.43 lb/hr, 3 hr avg.; 90.77 TPY	Low NO <sub>x</sub> Combustors and SCR
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)</b>	<b>Each Unit 283 MMBtu/hr 22.5 MW</b>	<b>22.65 ppm<sub>vd</sub> at 15% oxygen, 3 hr avg., &gt; 50% load</b>	<b>Dry Low NO<sub>x</sub> Combustors, Good Combustion Practices</b>
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	30 MW 290 MMBtu/hr each unit	25 ppm <sub>d</sub> @ 15%, > 50% load	Dry Low NO <sub>x</sub> Combustor

### **RBLC Review**

The vast majority of entries for NO<sub>x</sub> control in the RBLC are for units over 180 MW. These units are typically installed by electric utilities and NO<sub>x</sub> is controlled by SCR and dry low NO<sub>x</sub> combustors. In addition, not all of the units operate in a open-simple cycle mode. The applicant proposes the installation of dry low NO<sub>x</sub> combustors. The emission rates of the individual units listed in the RBLC must be reviewed carefully because NO<sub>x</sub> emissions can vary significantly depending on the load point selected to set the emission rate. The very lowest emission rate is 2.5 ppm<sub>v</sub> for a 70 MW unit and 25 ppm<sub>v</sub> for a 30 MW unit. The proposed MFC units are 22.5 MW, each. BACT limits for NO<sub>x</sub> generally increase as the size of the combustion turbine decreases. The applicant proposed a NO<sub>x</sub> BACT limit which is similar to the Sabine Pass LNG Terminal, which is the closest unit in size to that proposed by Midwest Fertilizer Corporation. SCR is typically installed on units in the 25 to 800 MW range. The units proposed by Midwest Fertilizer Corporation are 22.5 MW, each.

### **Applicant Proposal**

The applicant proposed BACT as:

- (a) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices and the use of dry low NO<sub>x</sub> combustors.
- (b) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.

The applicant provided an economic analysis of the use of SCR on the open-simple cycle combustion turbines with heat recovery to demonstrate to IDEM, OAQ that the use of SCR is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
SCR	103.43 tons per year	93.09 tons per year (90% reduction)	\$7,489,200	\$1,451,490	\$2,154,500	\$23,145	Ammonia Emissions, Additional Electrical Required
Capital Recovery Factor = 0.09439 ( 7% for a 20 year life cycle)							

The economic analysis indicates the level of NO<sub>x</sub> reduction does not justify the addition of selective catalytic reduction. In addition, the applicant has proposed an emission rate below a previously issued BACT for the turbine closest to its size. The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices and the use of dry low NO<sub>x</sub> combustors.
- (b) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Fuel Specifications
- (b) Good Combustion Practices
- (c) Oxidation Catalyst

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluates all identified control methods below:

- (a) **Fuel Specifications**  
Selection of a low carbon fuel will reduce the amount of carbon available for the conversion to CO. Therefore, fuel specifications are a feasible CO control option for the combustion turbines.
- (b) **Good Combustion Practices**  
CO emissions result from incomplete combustion when there is insufficient residence time at high temperature. As with NO<sub>x</sub>, CO emissions vary as the operating load of the turbine varies. Also, the methods used to reduce NO<sub>x</sub> will increase CO emissions. Proper management of the combustion process will result in a reduction in CO. Therefore, good combustion practices is a feasible control option.
- (c) **Oxidation Catalyst**  
The primary CO control method used in combustion turbines is catalytic oxidation. In fact, some SCR units incorporate CO oxidation modules to reduce CO and NO<sub>x</sub> simultaneously. CO catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. CO catalysts on gas turbines can achieve up to 90% reduction in CO emissions. Therefore, catalytic oxidation is a technically feasible control option of the open-simple cycle combustion turbines with heat recovery.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ ranked all feasible control technologies below:

- (a) Oxidation Catalyst – up to 90% control
- (b) Good Combustion Practices – less than 90% control
- (c) Fuel specifications – minimal reduction

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW	2 ppmv @ 15% 3 hr avg.	Ox Catalyst SCR
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	4 ppmv @15%, 1 hr avg. 3.7 lb/hr, 30 day rolling, 32 TPY	Ox Catalyst
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)</b>	<b>Each Unit 283 MMBtu/hr 22.5 MW</b>	<b>0.03 lb/MMBtu, 3 hr avg., &gt; 50% peak load</b>	<b>Good Combustion Practices</b>
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	80 MW	18.4 lb/hr, 30 day rolling	Good Combustion and Cat Oxidation
DE-0023	NRG Energy Center Dover	06/05/13	Gas Turbine with HRSG	One 655 MMBtu/hr (70 MW)	0.032 lb/MMBtu 1 hr avg. 19.54 lb/hr, 1 hr avg.	Ox Catalyst 0.3 lb/MW-hr
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW each unit	17.5 ppmv@15% 1 hr rolling avg.	Good Combustion
WY-0061	Black Hills Corporation – Neil Simpson Two	05/10/04	Combined Cycle Combustion Turbine	40 MW	37.2 ppmv @ 15%, 1 hr avg., 43.8 lb/hr, 1 hr avg.	Good Combustion

#### **RBLC Review**

The RBLC indicates the use of catalytic oxidation and good combustion practices are the methods used to control CO emissions in natural gas-fired combustion turbines. The applicant is proposing an emission rate of 0.03 lb/MMBtu. The lowest entries are from the Vernon City Light and Power turbine and the Black Hills Power turbine. These units are significantly larger units and use oxidation catalyst to control CO. The proposed emission rate is below the most recent BACT entry from the NRG Energy Center in Delaware. The NRG Energy Center turbine is also significantly larger and uses an oxidation catalyst.

### Applicant Proposal

The applicant proposed the following for BACT:

- (a) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average; and
- (b) CO emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by proper design, and good combustion practices.

The following economic analysis is presented to display the cost effectiveness of catalytic oxidation for control of CO:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
Catalytic Oxidation	37.19 TPY	27.89 TPY (75% Control)	\$46,097,520	\$4,846,593	\$5,992,677 + \$4,846,593 = \$10,839,270	\$388,644	Additional emissions due to makeup fuel to heat exhaust to catalyst activation temperature.
Capital Recovery Factor = 0.13 ( 5% for a 10 year life cycle)							

The economic analysis presented by the applicant shows catalytic oxidation is not a cost effective control option for small natural gas-fired combustion turbines.

### Step 5: Select BACT

IDEM, OAQ has established CO BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average; and
- (b) CO emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by proper design, and good combustion practices.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Good Combustion Practices
- (b) Oxidation Catalyst

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluates all identified control methods below:

- (a) **Good Combustion Practices**  
VOC emissions in gas combustion turbines result from incomplete combustion. These VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for the gas combustion turbines.
- (b) **Oxidation Catalyst**  
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reduction of 85% to 90%. The use of an oxidation catalyst is a feasible control technology for the combustion turbines.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ ranks all feasible control methods below:

- (a) Oxidation Catalyst – 85% to 90% control
- (b) Good Combustion Practices – less than 85% control

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW Combined Cycle Turbine	2 ppmv @ 15%, 1 hr avg.	Ox Catalyst SCR
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Two Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)</b>	<b>Each Unit</b> <b>283 MMBtu/hr</b> <b>22.5 MW</b>	<b>2.5 ppm<sub>vd</sub> @ 15%</b> <b>1 hr avg.</b>	<b>Good Combustion Practices</b>
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW, each	2.5 ppmv @15%, 1 hr rolling	Good Combustion
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	30 MW, 290 MMBtu/hr, each	1.2 lb/hr, maximum 4.84 TPY, maximum	Nat Gas and Good Combustion
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	3 ppmv @15%, 1 hr avg. 3 lb/hr, 3hr avg. 14.7 TPY	Ox Catalyst
DE-0023	NRG Energy Center Dover	06/05/13	Combined Cycle Combustion Turbines	One 655 MMBtu/hr (70 MW)	6.4 lb/hr, 1 hr avg.	Ox Catalyst
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two Gas Turbines with HRSG	35 MW, each	6.14 lb/hr 40.88 TPY	Combustion Control

#### **RBLC Review**

VOC control methods listed in the RBLC include good combustion practices and the use of an oxidation catalyst. Existing RBLC entries indicate VOC emission rates range from a low of 2 ppm<sub>vd</sub> to well over 8 ppm<sub>vd</sub>. The applicant proposed an emission rate of 2.5 ppm<sub>vd</sub>. The proposed rate is the lowest level of control for any unit in the RBLC except for the Vernon City facility, which is a combined cycle plant and is significantly larger than the MFC facility. The Vernon City facility uses an oxidation catalyst to achieve the 2 ppm<sub>vd</sub> emission rate.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub>, based on a one-hour average.

- (b) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices; and
- (c) Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas.

The applicant provided the following cost effectiveness analysis:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
Catalytic Oxidation	8.68 TPY	1.74 TPY (20% Control)	\$46,097,520	\$4,846,593	\$5,992,677 + \$4,846,593 = \$10,839,270	\$6,229,465	Additional emissions due to makeup fuel to heat exhaust to catalyst activation temperature.
Capital Recovery Factor = 0.13 ( 5% for a 10 year life cycle)							

#### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average.
- (b) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices; and
- (c) Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas.

#### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Fuel Specifications;
- (b) Good Combustion Practices; and
- (c) Carbon Capture and Sequestration (CCS).

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Fuel Specifications**

Greenhouse gas emissions from the natural gas-fired combustion turbines are directly related to the carbon content of the fuel and the efficiency of the combustion process. Natural gas contains approximately 34 pounds of carbon per million Btu. Fuel oil contains approximately 48 pounds of carbon per million Btu. Ash free coal contains 66 pounds of carbon per million Btu. Therefore, the selection of a low carbon fuel such as natural gas will reduce greenhouse gas emissions. Fuel specifications are a feasible control technology for greenhouse gas emissions.

### **(b) Good Combustion Practices**

Greenhouse gas emissions from the natural gas-fired combustion turbines are directly related to the carbon content of the fuel and the efficiency of the combustion process. Management of the combustion process will result in more complete combustion which reduces methane emitted from the turbines. Because more complete combustion can reduce methane emissions, good combustion practices are a feasible control technology for the natural gas combustion turbines.

### **(c) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. It was determined that CCS is not available to Midwest Fertilizer Corporation. Therefore, it is not a feasible control option.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control technologies. Therefore, no ranking is necessary.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – Greenhouse Gases (GHG)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
VA-0319	Gateway Green Energy	05/02/13	Two Combustion Turbines	80 MW, each	<u>CO<sub>2</sub>e</u> 1,050 lb/MW-hr, 12 month avg.  295,961 TPY	Natural gas, high efficiency design, max heat rate of 8,983 Btu/kW-h
DE-0023	NRG Energy Center Dover	06/05/13	Two Combined Cycle Combustion Turbines	One 655 MMBtu/hr (70 MW)	<u>CO<sub>2</sub>e</u> 1,085 lb/MW-hr, 12 month rolling avg.	None

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Open-Simple Cycle Combustion Turbines (EU-013A/B) – Greenhouse Gases (GHG)						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0256	Westlake Vinyls Company	04/03/12	Three Cogeneration Turbines	50 MW 475 MMBtu/hr, each unit	<u>CO<sub>2</sub>e</u> 55,576.77 lb/hr, maximum 243,426.26 TPY	Natural Gas and Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	<u>Each Unit</u> 283 MMBtu/hr 22.5 MW	<u>CO<sub>2</sub></u> 144,890 ton/12 month rolling 116.89 lb/MMBtu, 3 hr avg., 12,666 Btu/kw-hr	Good Engineering Design and Combustion Practices, Nat Gas

#### RBLC Review

The RBLC includes three greenhouse gas BACT determinations. Emission controls included the use of a low carbon fuel, good engineering design and good combustion practices. As with the other pollutants, emission rates of greenhouse gases increases as the electrical capacity of the generator increases. The unit closest to the Midwest Fertilizer Corporation is the Westlake Vinyls Company cogeneration turbines. GHG BACT for this unit was selected to match the emission rate corresponding to the emission factor listed in 40 CFR 98. Midwest Fertilizer Corporation, in a like manner, proposed the use of the emission factor from 40 CFR 98, along with a thermal efficiency.

#### Applicant Proposal

The applicant proposed the following for BACT:

- Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas;
- Greenhouse gas emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by proper design and good combustion practices;
- Thermal efficiency of each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month; and
- CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 116.89 lb/MMBtu, based on a three-hour average.

#### Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the open-simple cycle combustion turbines (EU-013A/B) as:

- The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- Greenhouse gas emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by proper design and good combustion practices;

- (c) Thermal efficiency of each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (d) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and
- (e) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Open-Simple Cycle Combustion Turbines (EU-013A/B)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the open-simple cycle combustion turbines (EU-013A/B) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design and good combustion practices at all times the units are in operation;
- (2) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (3) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0019 lb/MMBtu, based on a three-hour average;
- (4) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average;
- (5) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of dry low NO<sub>x</sub> combustors;
- (6) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.
- (7) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average;
- (8) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average;

- (9) Thermal efficiency of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) emissions shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and
- (11) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.

<b>BACT Analysis – Natural Gas Auxiliary Boilers (EU-012A/B/C)</b>
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**Emission Unit Description**

- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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.

**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) **Cyclones**

As discussed under the particulate matter BACT for the reformer furnace, the concentration of PM, PM<sub>10</sub> and PM<sub>2.5</sub> are extremely low for natural gas combustion. IDEM, OAQ expects no more than 0.005 grains/cubic foot. This low level of pollutant loading is already well below the normal removal efficiency of a cyclone. Therefore, a cyclone is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).

(b) **Wet Scrubbers**

Typical loadings for wet scrubbers range from 0.1 to 50 grains per cubic foot of exhaust gas. The concentration of PM, PM<sub>10</sub> and PM<sub>2.5</sub> are extremely low for natural gas combustion. IDEM, OAQ expects a loading of no more than 0.005 grains/cubic foot. This low level of pollutant loading is already well below the normal removal efficiency of a wet scrubber. Therefore, a wet scrubber is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).

(c) **Electrostatic Precipitators**

An electrostatic precipitator is a control device that uses electrical forces to collect charged particles on collector plates. This control device is typically used to control particulate loading in the 0.5 to 50 grains per cubic foot range. As with the cyclone and wet scrubber, the emission rate from natural gas combustion is well below the typical loading of an electrostatic precipitator. Therefore, the electrostatic precipitator is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).

(d) **Fabric Filter Dust Collectors (Baghouse)**

A typical baghouse design outlet concentration is 0.005 grains per cubic foot. Since the result of combustion of this source is already at the typical design outlet loading of the baghouse, fabric filters are not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).

(e) **Fuel Specification – Clean Burning Fuel**

Clean burning fuels, such as natural gas, have a very low potential to generate particulate emissions. Fuel specifications are a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).

(f) **Good Combustion Practices**

Good combustion practices as well as operation and maintenance of the boiler to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the auxiliary boilers (EU-012A/B/C):

(a) Fuel Specification – Clean Burning Fuel

(b) Good Combustion Practices

Both control methods have been selected by the applicant for implementation on the auxiliary boilers. Therefore, a ranking is not necessary.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Auxiliary Boilers (EU-012A/B/C) – PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0024 lb/MMBtu, avg. 3 tests; 1.06 ton/12 month rolling	Good Combustion Practices
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Auxiliary Boilers (EU-012A/B/C)</b>	<b>218.6 MMBtu/hr Each</b>	<b>PM – 1.9 lb/MMCF PM<sub>10</sub> – 7.6 lb/MMCF PM<sub>2.5</sub> – 7.6 lb/MMCF, 3 hr avg., 1,501.91 MMCF/12 month rolling</b>	<b>Good Combustion Practices, Proper Design, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to D	218 MMBtu/hr, Each	PM – 1.9 lb/MMCF PM <sub>10</sub> – 7.6 lb/MMCF PM <sub>2.5</sub> – 7.6 lb/MMCF, 3 hr avg.; 2,800 MMCF/12 month rolling over 4 units	Good Combustion Practices, Proper Design, natural gas
LA-0231	Lake Charles Cogeneration	06/22/09	Auxiliary Boiler	938.3 MMBtu/hr	6.99 lb PM <sub>10</sub> /hr, filterable and condensable, max.	Good Design and Operation
OH-0307	Biomass Energy South Point	04/04/06	Auxiliary Boiler	247 MMBtu/hr	0.0070 lb/MMBtu, 1.73 lb/hr, 3.26 ton/year	None
TX-0371	Corpus Christi Energy Center	02/04/00	Auxiliary Boilers 1 to 3	315 MMBtu/hr	0.005 lb/MMBtu, filterable, 1.57 lb/hr, maximum	None
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.20 MMBtu/hr	0.82 lb/hr, PM <sub>10</sub> filterable, 3 hr avg., 0.0070 lb/MMBtu	Good Combustion, Low Sulfur Fuel
PA-0187	Gray's Ferry Cogen Partnership	03/21/01	Auxiliary Boiler	1,119 MMBtu/hr	PM/PM <sub>10</sub> -0.005 lb/MMBtu, filterable, 34.4 lb/hr	Good Combustion Practices



### **RBLC Review**

PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from all of the auxiliary boilers in the RBLC are controlled by good combustion practices. Particulate emissions from natural gas-fired combustion sources are already extremely low and add-on controls are not practical. The emission limits for the Corpus Christi Energy Center and Gray's Ferry Cogeneration Partnership appear to be lower emission rates; however, the emission rates shown only include filterable particulate matter. Once condensable particulate matter is included, the emission rates are identical to the applicant's proposal. The particulate matter limits for an auxiliary boiler at the Iowa Fertilizer Company were the lowest emission rates found.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (c) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;
- (d) Natural gas usage in each natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (e) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM<sub>10</sub> and PM<sub>2.5</sub>. The proposed emission limits of 1.9 and 7.6 lb/MMCF are the default emission factors for natural gas combustion found in AP-42 for PM and PM<sub>10</sub>, PM<sub>2.5</sub>, respectively. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) at an emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM, OAQ believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

**Step 5: Select BACT**

IDEM, OAQ has established the following as BACT for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> for the auxiliary boilers (EU-012A/B/C):

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (c) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;
- (d) Natural gas usage in each natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (e) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the auxiliary boilers (EU-012A/B/C) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction (SCR);
- (b) Selective Non-Catalytic Reduction (SNCR);
- (c) Low NO<sub>x</sub> Burner (LNB);
- (d) Flue Gas Recirculation (FGR);
- (e) Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR); and
- (f) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

All NO<sub>x</sub> control strategies are discussed below:

- (a) **Selective Catalytic Reduction (SCR)**  
Selective catalytic reduction (SCR) is typically installed on stable steady state processes. The efficiency of NO<sub>x</sub> control will be reduced for processes that are not stable, require frequent changes in the mode of operation, or are installed on units with short operating times. This is due to the fact that SCR operation is dependent on the operating temperature of the process. SCR is effective in a narrow temperature range of 500 °F to 1,100 °F. The natural gas-fired auxiliary boilers will each operate up to 7,008 hours per year. While this is not continuous operation, it is stable enough for effective operation of an SCR control device. SCR is a feasible control technology for NO<sub>x</sub>.

(b) **Selective Non-Catalytic Reduction (SNCR)**

SNCR is similar to SCR, except it is operated without a catalyst bed. This control technology is well suited to exhaust gases that would foul a catalyst bed. SNCR does require a higher operating temperature for the reduction of NO<sub>x</sub> to occur. The reaction must occur between 1,600 °F and 2,000 °F. The reaction temperature is significantly higher than the exhaust temperature of the auxiliary boilers. This would require heating of the exhaust gas to at least 1,600 °F. The additional heating would result in an increase of most of the other regulated pollutants. SNCR is not a technologically feasible control option for the auxiliary boilers due to the energy requirements to heat the exhaust gas.

(c) **Low NO<sub>x</sub> Burner (LNB)**

Low NO<sub>x</sub> burners can reduce the formation of NO<sub>x</sub> through the careful control of the air-fuel mixture during combustion. Low NO<sub>x</sub> burners are more of a design feature than a control device. This technology is widely used on boilers and is a feasible control option for the auxiliary boilers.

(d) **Flue Gas Recirculation (FGR)**

Flue gas recirculation can reduce NO<sub>x</sub> emissions by recirculating a portion of the flue gas to lower the flame temperature during combustion. Like low NO<sub>x</sub> burners, it is a design feature more than a control device. FGR is widely used on boilers and is a feasible control option for the auxiliary boilers.

(e) **Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)**

Low NO<sub>x</sub> burners and FGR can be used in conjunction to achieve higher overall emission reductions. The combination of the control devices is a feasible control option for the auxiliary boilers.

(f) **Good Combustion Practices**

Good combustion practices as well as operation and maintenance of the boiler to keep it in good working order per the manufacturer's specifications will minimize NO<sub>x</sub> emissions. Good combustion practices are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control technologies for NO<sub>x</sub> control are ranked below:

- (a) Selective Catalytic Reduction – up to 90% control
- (b) Low NO<sub>x</sub> burners with Flue Gas Recirculation – up to 90% control
- (c) Low NO<sub>x</sub> Burners – up to 50% control
- (d) Flue Gas Recirculation – up to 25% control
- (e) Good Combustion Practices – less than 25% control

Typically the combination of low NO<sub>x</sub> burners and flue gas recirculation are capable of achieving 55% to 60% control. The applicant is proposing installation of LNB and FGR to achieve the same level of reduction as SCR. This would represent top BACT.

To estimate 90% NO<sub>x</sub> emission reduction, IDEM used the uncontrolled NO<sub>x</sub> emission factor from AP-42, Chapter 1.4, Table 1.4-1 SCC 1-02-006-01 of 190 lb NO<sub>x</sub> / MMBtu (0.19 lb/MMBtu). If the practical limit of NO<sub>x</sub> removal were 90%, a boiler would be expected to achieve a NO<sub>x</sub> emission rate of 0.019 lb/MMBtu. The Iowa Fertilizer Corporation proposed a NO<sub>x</sub> emission rate of 0.0125 lb/MMBtu, which represents a 93.4% reduction. This level of reduction exceeds a level IDEM considers practical and achievable at all times over the life of the unit. MFC proposed an emission rate of 0.02 lb/MMBtu or an 89.5% reduction. MFC will achieve the lowest NO<sub>x</sub> emission rate for an auxiliary boiler listed in the RBLC that has been demonstrated in practice. This is top BACT.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Auxiliary Boilers (EU-012A/B/C) – NO<sub>x</sub> BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Co	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu, 30 day avg., 5.52 ton/12 month rolling	Low NO <sub>x</sub> Burner, FGR
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Auxiliary Boilers (EU-012A/B/C)</b>	<b>218.6 MMBtu/hr</b>	<b>20.40 lb/MMCF, 3 hr average, 1,501.91 MMCF/12 month rolling</b>	<b>Low NO<sub>x</sub> Burners, FGR, Good Combustion Practices, Proper Design, Natural Gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Boilers EU-011A to EU-011D	218 MMBtu/hr Each	20.40 lb/MMCF, 24 hr avg., 2,802 MMCF/12 month rolling, over 4 boilers	Ultra Low NO <sub>x</sub> Burner, FGR
NJ-0043	Liberty Gen. Station	03/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu, 7.2 lb/hr, max.	SCR
CO-0052	Rocky Mountain Energy Ctr.	08/11/02	Natural Gas Fired Boiler (Aux. Boiler)	129 MMBtu/hr	0.038 lb/MMBtu 1,900 hr/yr	Low NO <sub>x</sub> Burner
TX-0386	Amella Energy Ctr.	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu, 6.2 lb/hr	None
TX-0411	Amella Energy Ctr,	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu	None

#### **RBLC Review**

A review of similar units in the RBLC indicates selective catalytic reduction, low NO<sub>x</sub> burners, flue gas recirculation are the principle NO<sub>x</sub> control strategies installed on auxiliary boilers. The lowest emission rate listed in the RBLC is 0.0125 lb/MMBtu for the Iowa facility. The Iowa units have not been constructed and this limit has not been demonstrated in practice. The next lowest limit is 20.4 lb/MMCF for the Ohio Valley Resources facility and it is the same as the emission rate proposed by the applicant.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (a) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (b) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of proper design and good combustion practices at all times the boilers are in operation;
- (c) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (d) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average; and
- (e) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant has proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the auxiliary boilers (EU-012/A/B/C) as:

- (a) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (b) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of proper design and good combustion practices at all times the boilers are in operation;
- (c) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (d) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average; and
- (e) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **CO BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following CO control technologies for the auxiliary boilers:

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

### **Step 2: Eliminate Technically Infeasible Options**

Each of the control technologies identified in Step 1 are discussed below:

(a) **Thermal Oxidation**

This control technology is typically used to control organic vapors. Theoretically, it is a control technology for CO. During combustion, CO is formed by the incomplete combustion of hydrocarbons. The additional thermal energy forces a more complete oxidation of the fuel resulting in the production of lower CO levels and higher carbon dioxide and water vapor levels. While theoretically possible, it normally is not feasible because of the low heating value of natural gas combustion products. Significant supplemental fuel will be required to heat the exhaust gas to the required operating temperature to achieve destruction. The boiler exhaust gas is at 350 °F and would require heating to at least 1,500 °F to achieve any reduction. In practice, thermal oxidation has not been installed on natural gas combustion sources. Thermal oxidation is not a feasible control technology for the auxiliary boilers.

(b) **Catalytic Oxidation**

Catalytic oxidation is a process similar to thermal oxidation. Catalytic oxidation uses a catalyst to allow the oxidation process to occur at a lower temperature. The exhaust gas would only be heated to 600 °F to 800 °F. Carbon Monoxide in the exhaust gas is combined with additional oxygen to form carbon dioxide and water vapor. As with thermal oxidation, it is not traditionally installed on natural gas combustion sources because of the low heating value of the exhaust gas. The combustion of additional fuel to raise the stack gas temperature will result in an increase in other regulated pollutants.

(c) **Flares**

Flares are another form of thermal oxidation. Theoretically, carbon monoxide is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in carbon monoxide. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 1,100 °F will result in an increase in other regulated pollutants. While technologically feasible, it is not a feasible control option for the auxiliary boilers.

(d) **Combustion Control**

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 CO emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

There is only one technically feasible control technology for carbon monoxide control in the auxiliary boilers. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Auxiliary Boilers (EU-012A/B/C) – CO BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0013 lb/MMBtu, avg. 3 runs; 0.57 ton/12 month rolling	Good Combustion Practices
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Auxiliary Boilers (EU-012A/B/C)</b>	<b>218.6 MMBtu/hr</b>	<b>37.22 lb/MMCF, 3 hr avg.; 1,501.91 MMCF/12 month rolling, each</b>	<b>Good Combustion Practices, Design, Natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	4 Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr Each	37.22 lb/MMCF, 3 hr avg., each 2,802 MMCF/12 month rolling, total	Good Combustion Practices, Design, Natural gas
CA-1212	City of Palmdale Hybrid Power	12/20/12	Auxiliary Boiler	110 MMBtu/hr	50 ppmvd @ 3% O <sub>2</sub> , 3 hr average	None
MI-0389	Consumers Energy	12/29/09	Auxiliary Boiler	220 MMBtu/hr	0.0350 lb/MMBtu, test method	Efficient Combustion
GA-0127	Southern Company	01/07/08	Auxiliary Boilers	200 MMBtu/hr	0.0370 lb/MMBtu, 3 hr average	None
OH-0310	American Municipal Power	10/08/09	Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr, 5.52 ton/12 month rolling; 400 ppmvd @ 3%, 3 hr avg.	None

#### **RBLC Review**

A review of similar emission units in the RBLC indicates add-on controls are not typically employed on natural gas combustion sources. If a control method is specified, it is good combustion practices. All of the RBLC entries used the AP-42 emission factor for open combustion of natural gas, except for Iowa Fertilizer Corporation (IFC) and American Municipal Power. American Municipal Power used a higher emission rate. The IFC boiler used a much lower emission rate.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) CO emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (c) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with the majority of RBLC entries for CO control on auxiliary boilers. IDEM, OAQ does not believe the IFC emission rate reflects BACT for CO control on natural gas combustion units because:

- (a) Add-on emission controls have been demonstrated to be infeasible.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the natural gas fired auxiliary boilers (EU-012A/B/C) as:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) CO emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (c) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.



## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for control of carbon monoxide in the natural gas-fired auxiliary boilers (EU-012A/B/C):

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ has evaluated all identified control technologies listed above:

#### **(a) Thermal Oxidation**

This control technology is typically used to control organic vapors. It is most effective in controlling emissions with high organic loading. The organic containing gas stream is mixed with additional fuel to oxidize the organic components to carbon dioxide and water vapor. The additional thermal energy forces a more complete oxidation of the fuel resulting in lower VOC levels and higher carbon dioxide emission levels. Catalytic Oxidation is not normally used on natural gas combustion products because of their low heating value. Significant supplemental fuel will be required to heat the exhaust gas to the required operating temperature to achieve destruction. The boiler exhaust gas is at 350 °F and would require heating to at least 1,500 °F to achieve any reduction. In practice, thermal oxidation has not been installed on natural gas combustion sources. Thermal oxidation is not a feasible control technology for the auxiliary boilers.

#### **(b) Catalytic Oxidation**

Catalytic oxidation is a process similar to thermal oxidation. Catalytic oxidation uses a catalyst to allow the oxidation process to occur at a lower temperature. The exhaust gas would only be heated to 600 °F to 800 °F. VOC in the exhaust gas is combined with additional oxygen to form carbon dioxide and water vapor. As with thermal oxidation, it is not traditionally installed on natural gas combustion sources because of the low heating value of the exhaust gas. The combustion of additional fuel to raise the stack gas temperature will result in an increase in other regulated pollutants. Catalytic oxidation is not a feasible control technology for the auxiliary boilers.

#### **(c) Flares**

Flares are another form of thermal oxidation. The VOC containing exhaust gas is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in volatile organic compounds. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 600 °F will result in an increase in other regulated pollutants. VOC control by flare is not a feasible control option for the auxiliary boilers.

#### **(d) Combustion Control**

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 VOC emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has proposed the only feasible control technology for the auxiliary boilers. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Auxiliary Boilers (EU-012A/B/C) – VOC BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0014 lb/MMBtu, 3 hr avg., 0.62 ton/12 month rolling	Good Combustion Practices
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Auxiliary Boilers (EU-012A/B/C)</b>	<b>218.6 MMBtu/hr</b>	<b>5.5 lb/MMCF, 3 hr avg.; 1,501.91 MMCF/12 month rolling</b>	<b>Good Combustion, Design, natural gas</b>
T 147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr Each	5.5 lb/MMCF, 3 hr avg.; 2,802 MMCF/12 month rolling, total	Combustion Practices, Design, Natural Gas
WV-0023	Longview Power, X	02/03/09	Auxiliary Natural Gas Boiler	225 MMBtu/hr	0.0054 lb/MMBtu, 3 hr rolling; 3,000 hr/yr	Use Natural Gas, Good Combustion Practices
OH-0310	American Municipal Power Generating	10/08/09	Auxiliary Natural Gas Boiler	150 MMBtu/hr	5.5 lb/MMCF 0.83 lb/hr 0.36 ton/12 month rolling	None
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Natural Gas Boiler	200 MMBtu/hr	50 ppmvd, 7% O <sub>2</sub> 1.6 lb/hr, 0.008 lb/MMBtu	CO Catalyst
TX-0386	Amella Energy Center	08/26/04	Auxiliary Natural Gas Boiler	155 MMBtu/hr	3.1 lb/hr, maximum	None

**RBLC Review**

A review of BACT determinations in the RBLC indicates add-on control technology is not typically used on natural gas-fired boilers. VOC emissions are exclusively controlled by good combustion practices and the use of a low carbon fuel, natural gas. The lowest emission rate achieved is at the Iowa Fertilizer Corporation (IFC) with the use of good combustion practices.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) VOC emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **Step 5: Select BACT**

IDEM, OAQ has established the following as VOC BACT for the auxiliary boilers:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) VOC emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

- (a) Carbon Capture and Sequestration (CCS);
- (b) Energy Efficient Design and Good Combustion Practices; and
- (c) Low Carbon Fuel.

#### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated each of the identified control options below:

- (a) **Carbon Capture and Sequestration (CCS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. IDEM, OAQ evaluated the capture and sequestration of all sources of greenhouse gases in the greenhouse gas BACT analysis for the reformer furnace. It was determined that CCS was not a feasible control option for the entire source because the technology is not available or applicable to Midwest Fertilizer Corporation.

(b) **Energy Efficient Design and Good Combustion Practices**

Good combustion practices and energy efficient design as well as operation and maintenance of the auxiliary boilers to keep them in good working order per the manufacturer's specifications will minimize GHG emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

(c) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of low carbon fuels such as natural gas is a technically feasible control option for the auxiliary boilers.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control options. Therefore, no ranking is necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Auxiliary Boilers (EU-012A/B/C) – GHG BACT</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. 1,501.91 MMCF/12 month rolling	Natural gas, Good Combustion/Design, 80% Efficiency (HHV)
T 147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr each	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. 2,802 MMCF/12 month rolling	Good Combustion Practices/Design, 80% efficiency, Natural gas
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, avg. 3 tests; CH <sub>4</sub> – 0.0023 lb/MMBtu, avg. 3 tests; N <sub>2</sub> O – 0.0006 lb/MMBtu, avg. 3 tests CO <sub>2e</sub> – 638 ton/12 month rolling	Good Combustion Practices

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Auxiliary Boilers (EU-012A/B/C) – GHG BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, 30 day rolling; CH <sub>4</sub> – 0.0023 lb/MMBtu, 3 run avg.; N <sub>2</sub> O – 0.0006 lb/MMBtu, 3 run avg. CO <sub>2</sub> e –51,748 ton/12 month rolling.	Good Combustion Practices
T147-30464-00060	Indiana Gasification	06/27/12	Auxiliary Boiler	172 MMBtu/hr	88,167 tons CO <sub>2</sub> /12 month rolling	81% Thermal Efficiency, Use Natural Gas, Efficient Design

#### **RBLC Review**

A review of the RBLC indicates greenhouse gas emissions are controlled by good combustion practices and design features to maximize the efficiency of the boiler. Efficient boilers will require less fuel which reduces greenhouse gas emissions. All of the entries use 117 lb/MMBtu for CO<sub>2</sub> emissions. This is equivalent to 59.61 ton CO<sub>2</sub>/MMCF.

#### **Applicant Proposal**

The applicant has proposed the following for BACT:

- The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- Greenhouse gas emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency; and
- Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

The applicant has accepted top BACT.

**Step 5: Select BACT**

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) Greenhouse gas emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (d) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- (e) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
- (f) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Auxiliary Boilers (EU-012A/B/C)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be as follows:

- (1) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC, and GHG emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (3) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (5) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;

- (6) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (7) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average;
- (8) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average;
- (9) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- (11) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
- (12) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

<b>BACT Analysis – Fugitive Emissions from Equipment Leaks (F-1)</b>
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**Emission Unit Description**

- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1.  
[40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> PSD Applicability**

Fugitive emissions from equipment leaks do not have a potential to emit particulate. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for PM, PM<sub>10</sub> and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> PSD Applicability**

Fugitive emissions from equipment leaks have the potential to emit NO<sub>x</sub> of 0.01 ton per year. IDEM, OAQ considers NO<sub>x</sub> emissions from these units as insignificant and has determined that it would be technically infeasible and not cost effective to require NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

**CO PSD Applicability**

Fugitive emissions from equipment leaks do not have a potential to emit carbon monoxide. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for CO and a BACT analysis is not required for this pollutant.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for VOC control from fugitive emission sources:

- (a) Leak Detection and Repair Program (LDAR)
- (b) No Control Option

### **Step 2: Eliminate Technically Infeasible Options**

#### **(a) Leak Detection and Repair Program (LDAR)**

A leak detection and control program (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fitting, sampling connections, etc. LDAR is a work practice that assists sources identify leaking equipment so that emissions can be reduced through systematic repair or replacement. The key to the effectiveness of fugitive emission control is the regularly scheduled inspections and a defined repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC emissions.

#### **(b) No Control Option**

It is possible that fugitive emissions from a source are so small that the time and cost required to establish and implement an LDAR program are not cost effective. Fugitive VOC emissions were estimated by the source at 14.39 tons per year. The use of no control is a technically feasible control option for the fugitive VOC emissions.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

- (a) LDAR (98% control)
- (b) No Control (0% control)

The applicant proposed an LDAR program which is top BACT. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Fugitive Emissions (F-1) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Fugitive Emissions (F-1)	NA	None	LDAR Program 40 CFR 60, Subpart VVa
T147-32322-00062	Ohio Valley Resources	09/25/13	Process Fugitive VOC	NA	None	LDAR Program 40 CFR 60, Subpart VVa
LA-0245	Valero, Hydrogen Plant	12/15/10	Fugitives FUG0030	NA	23.74 TPY	LDAR that meets LA Refinery MACT
TX-0575	Sabina Petrochemicals	08/20/10	ALKFUG, BDEFUG, UTILFUG	NA	9.01 TPY	LEAR Leak Detection and Repair Program 98% Control
FL-0318	Highlands Ethanol Facility	12/10/09	Fugitive VOC Equipment Leaks	NA	19.6 TPY	LDAR Program 40 CFR 60, Subpart VVa
LA-0197	Alliance Refinery	07/21/09	Unit Fugitives	NA	13.22 lb/hr 57.89 TPY	LDAR that meets LA Refinery MACT
FL-0322	Southeast Renewable Fuels	12/23/10	Fugitive VOC Emissions	NA	6.52 TPY	LDAR Program 40 CFR 60.4821a through 60.482-10a or 60.480a(e)

#### RBLC Review

A review of the RBLC for similar emission sources indicates fugitive VOC emissions are controlled exclusively by an LDAR program.

#### Applicant Proposal

The applicant has proposed the following for BACT:

- (a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program.

#### Step 5: Select BACT

IDEM, OAQ has established the following as VOC BACT for fugitive VOC emissions:

- (a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The lead detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

## Greenhouse Gas BACT

### **Step 1: Identify Potential Control Technologies**

The only potential control technology or operational practice to control fugitive greenhouse gas emissions is a leak detection and repair program.

### **Step 2: Eliminate Technically Infeasible Options**

The source estimates fugitive greenhouse gas emissions of 1,215 tons as CO<sub>2</sub>e will be emitted. The applicant estimates there will be small amounts of fugitive GHG emissions from equipment leaks, compressor leaks, valve and connector leaks, etc. These fugitive emissions are small in the overall operation of the facility but must be addressed. An LDAR program is technically feasible for the fugitive GHG emissions from this source.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

There is only one control option; therefore, a ranking or further analysis is not needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Fugitive Emissions (F-1) – Greenhouse Gases</b>						
<b>RBLC ID Permit #</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
FL-0330	Port Dolphin Energy	12/01/11	Fugitive GHG Emissions	NA	No Numerical Limits	Gas Leak Detection System
LA-0257	Sabine Pass LNG Terminal	12/06/11	Fugitive GHG Emissions	NA	89,629 TPY CO <sub>2</sub> e, maximum	LDAR Program
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, Monitor Total Hydrocarbon Instead of VOC
T147-30464-00060	Indiana Gasification	06/27/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, visual/audio inspection of compressors
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Fugitive GHG Emissions (F-1)</b>	<b>NA</b>	<b>None</b>	<b>None</b>
T 147-32322-00062	Ohio Valley Resources	09/25/13	Fugitive GHG Emissions	NA	None	None

### **RBLC Review**

The RBLC has limited entries for fugitive greenhouse gas emissions. The only control method listed for fugitive GHG control was the use of a leak detection and repair program (LDAR). Fugitive GHG emissions of the Ohio Valley Resources facility were so small, no control option was selected.

### **Applicant Proposal**

The applicant proposed the no control option.

### **Step 5: Select BACT**

IDEM, OAQ believes the greenhouse gas emissions from fugitive sources are insignificant. No additional BACT requirements will be imposed.

<p align="center"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for Fugitive Emissions (F-1)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for fugitive emissions (F-1) shall be as follows:

- (1) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The lead detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

<p align="center"><b>BACT Analysis – Truck Loading Operation (EU-020)</b></p>
---

#### **Emission Unit Description**

- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.

#### **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses).

#### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

- (a) **Cyclones**

Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the truck loading operation because it is ineffective in control of fine particulate matter.

- (b) **Wet Scrubber**

A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may

require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the truck loadout operation.

(c) **Electrostatic Precipitator (ESP)**

An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the truck loading operation because of the intermittent operation of the emission unit and its cost.

(d) **Fabric Filter Dust Collector**

Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the truck loading operation.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

(a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control

(b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the truck loading operation. This is top BACT. No additional analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Truck Loading Operation (EU-020) – PM, PM<sub>10</sub>, and PM<sub>2.5</sub></b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Truck Loading Operation (EU-020)	3,080 tons granulated Urea per day	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.12 lb/hr, 3 hr average	Baghouse
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

### **RBLC Review**

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and have higher emission rates than the applicant's proposal.

### **Applicant Proposal**

The applicant has proposed the following for BACT:

- (a) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall not exceed 0.12 lb/hr, based on a three-hour average.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the truck loadout operation identified as EU-020 as follows:

- (a) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The truck loading operation (EU-020) does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the truck loading operation for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Truck Loadout Operation (EU-020)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the truck loadout operation (EU-020) shall be as follows:

- (1) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.

<b>BACT Analysis – Rail Loading Operation (EU-021A)</b>
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### **Emission Unit Description**

- (I) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-21A.

## **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP);
- (d) Fabric Filter Dust Collectors (Baghouses)

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

- (a) **Cyclones**  
Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the rail loading operation because it is ineffective in control of fine particulate matter.
- (b) **Wet Scrubber**  
A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the rail loading operation.
- (c) **Electrostatic Precipitator (ESP)**  
An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the rail loading operation because of the intermittent operation of the emission unit and its cost.
- (d) **Fabric Filter Dust Collector**  
Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the rail loading operation.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

- (a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control
- (b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the rail loading operation. This is top BACT. No additional analysis is required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Rail Loading Operation (EU-021A) – PM, PM<sub>10</sub>, and PM<sub>2.5</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Rail Loading Operation (EU-021A)</b>	<b>3,080 ton urea per day</b>	<b>PM, PM<sub>10</sub>, PM<sub>2.5</sub> – 0.21 lb/hr, 3 hr avg.</b>	<b>Baghouse</b>
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

#### **RBLC Review**

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and have higher emission rates than the applicant's proposal.

#### **Applicant Proposal**

The applicant has proposed the following for BACT:

- (a) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall not exceed 0.21 lb/hr, based on a three-hour average.

**Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the rail loadout operation identified as EU-021A as follows:

- (a) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.

**NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The rail loading operation (EU-021A) does not have NO<sub>x</sub>, CO, VOC, or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the rail loading operation for these pollutants and BACT analyses are not required for these pollutants.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Rail Loading Operation (EU-021A)</b></p>
--

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for rail loading operation (EU-021A) shall be as follows:

- (1) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.

<p><b>BACT Analysis – Urea Junction Operation (EU-021B)</b></p>
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**Insignificant Activity**

- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses).



### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

(a) **Cyclones**

Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the urea junction operation because it is ineffective in control of fine particulate matter.

(b) **Wet Scrubber**

A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the urea junction operation.

(c) **Electrostatic Precipitator (ESP)**

An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the urea junction operation because of the intermittent operation of the emission unit.

(d) **Fabric Filter Dust Collector**

Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the urea junction operation.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

(a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control

(b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the rail loading operation. This is top BACT. No additional analysis is required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Urea Junction Operation (EU-021B) – PM, PM <sub>10</sub> , and PM <sub>2.5</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Urea Junction Operation (EU-021B)	3,080 tons urea per day	PM, PM <sub>10</sub> , PM <sub>2.5</sub> – 0.21 lb/hr, 3 hour average	Baghouse
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

#### RBLC Review

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and similar emission rates to the applicant's proposal.

#### Applicant Proposal

The applicant has proposed the following for BACT:

- The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

#### Step 5: Select BACT

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the urea junction operation identified as EU-021B as follows:

- The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The urea junction operation (EU-021B) does not have NO<sub>x</sub>, CO, VOC, or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea junction operation for these pollutants and a BACT analyses are not required for these pollutants.

#### **Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Urea Junction Operation (EU-021B)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for urea junction operation (EU-021B) shall be as follows:

- (1) The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

#### **BACT Analysis – Ammonia Storage Flare (EU-016)**

##### **Insignificant Activity**

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]

##### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

##### **Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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 good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

##### **Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

- (a) **Flare design and good combustion practices**  
Flare design and operation are key elements in the emissions performance of flares. The ammonia storage flare (EU-016) 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 use of flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).

(b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (1) Proper flare design and good combustion practices; and
- (2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Storage Flare (EU-016) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	PM - 0.0019 lb/MMBtu PM <sub>10/2.5</sub> - 0.0075 lb/MMBtu, 3 hr avg. both	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	PM - 0.0019 lb/MMBtu PM <sub>10/2.5</sub> - 0.0075 lb/MMBtu, 3 hr avg. both	Good combustion practice/flare design, flare minimization plan, natural gas

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Storage Flare (EU-016) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

#### RBLC Review

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42 emission factor, Chapter 1.4. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

#### Applicant Proposal

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

#### Step 5: Select BACT

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for ammonia storage flare (EU-016):

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

#### **NO<sub>x</sub> BACT**

##### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the ammonia storage flare (EU-016):

- (1) Flare design and good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the ammonia storage flare (EU-016).
- (b) **Process flaring minimization practices**  
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	0.068 lb/MMBtu, 3 hr avg. pilot and 125.00 lb/hr venting, 168 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.068 lb/MMBtu, pilot 3 hr avg., and 125.00 lb/hr venting, 168 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion 40 CFR 60.18
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the ammonia storage flare (EU-016) as:

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
- (c) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (d) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and



- (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (e) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (f) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the ammonia storage flare (EU-016):

- (1) Flare design and good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.  
  
The use of proper flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).
- (b) **Process flaring minimization practices**  
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.  
  
The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).
- (c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:
  - (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.

- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b>						
<b>Ammonia Storage Flare (EU-016) – CO</b>						
<b>RBLCL ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Ammonia Storage Flare (EU-016)</b>	<b>1.5 MMBtu/hr</b>	<b>0.37 lb/MMBtu, 3 hr average</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.37 lb/MMBtu 3 hr average	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion 40 CFR 60.18

### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the ammonia storage flare (EU-016) shall be controlled by good combustion practices;
- (b) CO emissions from the ammonia storage flare (EU-016) shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the ammonia storage flare (EU-016) as:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (2) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by the use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.

## **VOC BACT**

### **Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the ammonia storage flare (EU-016):

- (1) Flare Design and Monitoring;
- (2) Process Flaring Minimization Practices; and
- (3) Flare Gas Recovery.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	0.0054 lb/MMBtu, 3 hr avg.	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.0054 lb/MMBtu, 3 hr avg.	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

#### **RBLC Review**

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

#### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the ammonia storage flare (EU-016) as:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.

- (2) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the ammonia storage flare (EU-016):

- (1) Carbon Capture and Sequestration (CCS);
- (2) Good Design and Combustion Practices;
- (3) Flare Minimization practices (FMP); and
- (4) Low Carbon Fuel for Pilot and Sweep Gas.

#### **Step 2: Eliminate Technically Infeasible Options**

##### **(a) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. Greenhouse gas emissions from the ammonia storage flare (EU-016) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the ammonia storage flare (EU-016).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the ammonia storage flare (EU-016).

(d) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Ammonia Storage Flare (EU-016) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Ammonia Storage Flare (EU-016)</b>	<b>1.5 MMBtu/hr</b>	<b>CO<sub>2</sub> – 116.89 lb/MMBtu, 3 hr average.</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	CO <sub>2</sub> – 52.05 lb/hr, 3 hr average.	Good combustion practice/flare design, flare minimization plan, natural gas

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Ammonia Storage Flare (EU-016) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr CH <sub>4</sub> -0.06 lb/hr N <sub>2</sub> O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### **RBLC Review**

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

#### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the ammonia storage flare (EU-016) as:

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.



- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Ammonia Storage Flare (EU-016)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the ammonia storage flare (EU-016) shall be as follows:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (2) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
- (7) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.
- (9) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (11) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operations, based on a three-hour average.

<b>BACT Analysis – Urea Synthesis Plant (EU-006)</b>
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**Insignificant Activity Description**

- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC PSD Applicability**

The urea synthesis plant (EU-006) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea synthesis plant for these pollutants and BACT analyses are not required for these pollutants.

**Greenhouse Gas BACT**

The urea synthesis plant (EU-006) has the potential to emit 3.2 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Urea Ammonium Nitrate Plant (EU-007)**

#### **Insignificant Activity Description**

- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and VOC PSD Applicability**

The urea ammonium nitrate plant (EU-007) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea ammonium nitrate plant for these pollutants and BACT analyses are not required for these pollutants.

#### **Greenhouse Gas BACT**

The urea ammonium nitrate plant (EU-007) has the potential to emit 1,038 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from the urea ammonium nitrate plant as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Emergency Generator (EU-014)**

#### **Insignificant Activity Description**

- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

#### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

##### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- (a) Add-on controls;
- (b) Good Combustion Practices; and
- (c) Usage Limitations.

##### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.

(b) **Good Combustion Practices**

This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.

(c) **Usage Limitations**

Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Generator (EU-014) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators CC009 - CC015	3,622 HP	0.0001 lb/hp-hr, PM <sub>10</sub> , filterable only, 0.4 lb/hr each	Good Combustion Practice, turbocharger
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators LX024–LX025	2,206 HP	0.0001 lb/hp-hr, PM <sub>10</sub> , filterable only, 0.2 lb/hr each	Good Combustion Practice, turbocharger
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Generator (EU-014)</b>	<b>3,600 HP</b>	<b>PM/PM<sub>10</sub>/PM<sub>2.5</sub> 0.15 g/hp-hr, 3 hr average; 500 hours/12 month rolling</b>	<b>Good Combustion</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690 HP	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.15 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Diesel-Fired Emergency Generator (EU-014) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.2 g/KW-hr, 3 test average; 0.22 ton/12 month rolling	Good Combustion Practices
FL-0322	Southeast Renewable Fuels	12/23/10	Emergency Generator	2,000 KW	PM-0.2 g/KW-hr, filterable and condensable	Comply with 40 CFR 60, Subpart IIII
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Emergency Generator	750 KW 1,005 HP	PM-0.2 g/KW-hr	Good Combustion, Tier 2 Engine

#### **RBLC Review**

None of the emergency generators in the RBLC include add-on control technology. Emissions of particulate are controlled by limiting the hours of operation of the generator and practicing good combustion practices. The two units located at the MGM Mirage in Nevada were constructed. However, the state of Nevada does not require testing of insignificant activities and the emission rates were never verified.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions shall be controlled by exercising good combustion practices; and
- (c) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per year.

In addition, IDEM, OAQ required a cost effectiveness analysis of these engines as part of the BACT analysis performed by Ohio Valley Resources. IDEM, OAQ updated this analysis to reflect 500 hours of operation of the emergency generator.

Control Alternative	Captured Emissions (TPY)	Emission Reduction (TPY)	Capital Cost (\$)	Operating Cost (\$/yr)	Total Annualized Costs (\$/yr) (b)	Cost Effectiveness (\$/ton)	Energy and Environmental Impacts
0.05 g/hp-hr, PTE at 500 hours	0.13	0.17	45,000	(a)	\$6,407	\$37,688	lower overall emissions, units have same HP
Baseline, 500 Hours, 0.15 g/hp-hr	0.30	---	---	---	---	---	---

**Notes:**

- (a) The annual operating costs and salvage value are assumed identical for both engine designs.  
(b) Capital Recovery Factor – 0.14238 (7%, 10 year lifecycle)

The emergency generator will operate 500 hours annually regardless of the generator selected. The emission reduction attributable to the lower emitting generator is only 0.17 tons per year and costs \$37,688 dollars per ton of emission reduction achieved. The lower emitting generator cannot be justified using a cost effectiveness analysis in this specific application.

**Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices; and
- The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- Add-on controls;
- Good Combustion Practices; and
- Usage Limitations.

### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.
- (b) **Good Combustion Practices**  
This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.
- (c) **Usage Limitations**  
Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Generator (EU-014) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Generator (EU-014)</b>	<b>3,600 HP</b>	<b>4.46 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690 HP	4.46 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 –015	3,622 HP	0.01 lb/Hp-hr 37.4 lb/hr, each unit	Turbocharger After-cooler
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 –025	2,206 HP	0.0131 lb/Hp-hr 28.98 lb/hr	Turbocharging, After-cooling, lean burn

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Diesel-Fired Emergency Generator (EU-014) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,680 HP	6.0 g/KW-hr, avg. 3 tests; 6.61 ton/12 month rolling	Good Combustion Practices
FL-0322	Southeast Renewable	12/23/10	Emergency Generator	2,682 HP	6.4 g/KW-hr	Comply 40 CFR 60, Subpart IIII
AK-0071	Chugach Electric	12/20/10	Black-Start Generator	2,010 HP	6.4 g/KW-hr, instantaneous	Turbocharger and After-cooler

#### **RBLC Review**

None of the emergency generators in the RBLC use add-on controls. If a control method is specified, it is good combustion practices. The Ohio Valley Resources emergency generator has a slightly lower emission rate. However, this difference is insignificant. They are essentially identical.

#### **Applicant Proposal**

- (a) NO<sub>x</sub> emissions shall not exceed 4.46 g/hp-hr;
- (b) NO<sub>x</sub> emissions shall be controlled by exercising good combustion practices; and
- (c) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per year.

The emission rate for the emergency generator proposed by the applicant represents top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;
- (b) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall be controlled by exercising good combustion practices; and
- (c) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.



## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- (a) Add-on controls;
- (b) Good Combustion Practices; and
- (c) Usage Limitations.

### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.
- (b) **Good Combustion Practices**  
This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.
- (c) **Usage Limitations**  
Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Generator (EU-014) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 to CC015	3,622 HP	0.0017 lb/Hp-hr 6.05 lb/hr, each	Good Combustion Practices, Turbocharger
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 and LX025	2,206 Hp	0.0018 lb/HP-hr 3.95 lb/hr, each	Good Combustion Practices, Turbocharger
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Generator (EU-014)</b>	<b>3,600 HP</b>	<b>2.61 g/hp-hr, 3 hr average; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690	2.61 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
AK-0076	Exxon-Port Thomson Production	08/20/12	Diesel-Fired Generators	2,314 HP	3.5 g/KW-hr	None
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,682 HP	3.5 g/KW-hr, 3 run avg.; 3.86 ton/12 month rolling	Good Combustion Practices
FL-0332	Highlands Biorefinery and Cogeneration	09/23/11	2000 KW Emergency Equipment	2,682 HP	3.5 g/KW-hr	Comply with 40 CFR 60, Subpart IIII

#### **RBLC Review**

None of the emergency generators in the RBLC include add-on control technology. Emissions of carbon monoxide are controlled by limiting the hours of operation of the generator and practicing good combustion practices. The two units located at the MGM Mirage in Nevada were constructed. However, the state of Nevada does not require testing of insignificant activities and the emission rates were never verified.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) The diesel-fired emergency generator (EU-014) shall not operate more than 500 hours per year;
- (b) CO emissions from the diesel-fired emergency generator (EU-014) shall be controlled by good combustion practices; and
- (c) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr.

### **Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) CO emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.
- (c) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average.

IDEM, OAQ is not requiring the applicant to meet the 0.77 g/hp-hr emission limitation of the MGM Grand because it appears to be an outlier. There have been other BACT determinations from other states issued after the MGM BACT with higher emission levels than those proposed by the applicant. In addition, the MGM engines were installed but were never tested to confirm actual emissions.

## **VOC BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency generator (EU-014) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Diesel-Fired Emergency Generator (EU-014) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
NV-0050	MGM Mirage	11/30/09	Diesel Generator	2,206 HP	0.0003 lb/HP-hr, 0.71 lb/hr, each	Turbocharger, Good Combustion
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Generator (EU-014)</b>	<b>3,600 HP</b>	<b>0.31 g/hp-hr, 3 hr avg. 500 hr/12 month rolling</b>	<b>Good Combustion</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator (EU-009)	4,690 HP	0.31 g/hp-hr, 3 hr avg., 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	0.4 g/KW-hr, avg. 3 test runs; 0.44 ton/12 month rolling	None
LA-0254	Entergy Louisiana	08/06/11	Diesel Generator	1,250 HP	1 g/hp-hr, annual average.	Good Combustion
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Emergency Generators 1 to 8	757 HP	4 g/KW-hr	Comply 40 CFR 60, Subpart IIII
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Diesel Generator	750 KW	6.4 g/KW-hr	Good Combustion Tier 2 Engine

#### **RBLC Review**

None of the emergency generators in the RBLC use add-on controls. If a control method is specified, it is good combustion practices. The lowest entry is for a 2,206 HP diesel generator at the MGM Mirage. It emission rate is equivalent to 0.14 g/hp-hr. The applicant proposes an emission rate of 0.31 g/hp-hr which is higher than the MGM Mirage but consistent with the recently issued Ohio Valley Resources VOC BACT. The MGM Mirage units were constructed but were never tested to verify actual emission rates.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) VOC emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.

- (c) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr.

The applicant's proposal represents a higher level of control than the Ohio Valley Resource VOC BACT. The MGM Mirage unit appears to be an outlier. The unit was installed but never tested. There are more recent BACT determinations with higher VOC emission rates in the RBLC. As such, IDEM, OAQ does not believe the MGM Mirage VOC BACT represents VOC BACT for the Midwest Fertilizer Corporation.

#### **Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) VOC emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.
- (c) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency generator (EU-014) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Generator (EU-014) – Greenhouse Gases</b>						
<b>RBLC ID Permit #</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Generator (EU-014)</b>	<b>3,600 HP</b>	<b>CO<sub>2</sub> – 526.39 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling</b>	<b>Good Combustion</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator (EU-009)	4,690 HP	CO <sub>2</sub> – 526.39 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	CO <sub>2</sub> e – 788.5 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, 3 test average; CH <sub>4</sub> – 0.0001 g/KW-hr, 3 test average	Good Combustion Practices
AK-0076	Exxon, Point Thomson Production Facility	08/20/12	Emergency Generator	1,750 KW	CO <sub>2</sub> – No Numerical Limit	Good Combustion, 40 CFR 60, Subpart IIII
MI-0402	Wolverine Power, Sumpter Power Plant	11/17/11	Diesel RICE	732 HP	CO <sub>2</sub> e – 716 lb/hr, test method	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Generator	1,250 HP	CO <sub>2</sub> – 163 lb/MMBtu	Proper Operation and Good Combustion
T147-30464-00060	Indiana Gasification	06/27/12	Emergency Generator ( 5 Units )	2 @ 1,341 HP 3 @ 575 HP	Total CO <sub>2</sub> emissions limited to 84 tons CO <sub>2</sub> per year	Good Design to meet NSPS/MACT

#### **RBLC Review**

None of the emergency generators listed in the RBLC use add-on control technology to control greenhouse gas emissions. The only method of control used is good combustion practices.

#### **Applicant Proposal**

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) GHG emissions shall be controlled by the use of good combustion practices.
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr.

The applicant has accepted top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the diesel-fired emergency generator (EU-014) as:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (b) GHG emissions shall be controlled by the use of good combustion practices; and
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency generator shall not exceed 526.39 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Diesel-Fired Emergency Generator (EU-014)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency generator (EU-014) shall be as follows:

- (1) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices;
- (3) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

**BACT Analysis – Fire Water Pump (EU-015)**

**Insignificant Activity**

- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015.  
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

**Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Fire Water Pump (EU-015) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Fire Water Pump (EU-015)</b>	<b>500 HP</b>	<b><u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Water Pump (EU-016)	481 HP	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Fire Pump	350 HP	<u>PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/Hp-hr, annual average	Ultra-Low Sulfur Diesel, Good Combustion Practices



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Fire Water Pump (EU-015) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0088	Archer Daniels Midland – Cedar Rapids	06/29/07	Fire Pump	540 HP	PM/PM <sub>10</sub> 0.15 g/HP-hr, 3 test average; 0.04 ton/12 month rolling	Tier 3 non-road Engine
IA-0095	Tate & Lyle Ingredients	09/19/08	Fire Pump	575 HP	PM/PM <sub>10</sub> 0.20 g/HP-hr, avg. 3 runs; 0.05 ton/12 month rolling	None
AZ-0046	Arizona Clean Fuels, Yuma	04/14/05	Fire Water Pump	5.46 MMBtu/hr 780 HP	PM-0.2 g/KW-hr	Certified by manufacturer to achieve limit
IA-0105	Iowa Fertilizer Company	10/26/12	Diesel Fire Pump	235 KW 315 HP	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.2 g/KW-hr, avg. 3 tests; 0.03 ton/12 month rolling	Good Combustion Practice

#### **RBLC Review**

A review of the RBLC indicates add-on controls are not a feasible option for the fire water pump. The only method of control for particulate is the use of good combustion practices. The lowest emission rate is 0.15 g/hp-hr. This emission rate was used as BACT in several other permits listed in the RBLC.

#### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (1) Good Combustion Practices;
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions shall each not exceed 0.15 g/hp-hr; and
- (3) Operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per year.

#### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month; and
- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average.

## NO<sub>x</sub> BACT

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Fire Water Pump (EU-015) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Fire Pump (EU-015)	500 HP	2.83 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	2.86 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	300 HP	3.75 g/KW-hr, avg. 3 tests; 0.49 ton/12 month rolling	Good Combustion Practices
LA-0251	Flopam, Inc.	04/26/11	Fire Pump	444 HP	3.0 g/KW-hr; 5.82 lb/hr; 0.29 TPY	None
ID-0018	Idaho Power Company	06/25/10	Fire Pump	267 HP	4.0 g/KW-hr	Tier 3 Engine, Good Combustion
SC-0113	Pyramax Ceramics	02/08/12	Fire Pump	500 HP	4.0 g/KW-hr	40 CFR 60, Subpart IIII
OH-0254	Duke Energy Washington County	08/14/03	Fire Pump	400 HP	14.5 g/Hp-hr 12.8 lb/hr 3.2 TPY	Combustion Control

### **RBLC Review**

A review of the RBLC indicates add-on controls are not a feasible option for the fire water pump. The only method of control for particulate is the use of good combustion practices. The lowest emission rate is 2.86 g/hp-hr for the fire pump at the Ohio Valley Resources facility. The applicant is proposing an emission rate below the lowest listed in the RBLC.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (1) Good Combustion Practices;
- (2) NO<sub>x</sub> emissions shall not exceed 2.83 g/hp-hr; and
- (3) Operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (1) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average; and
- (3) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Diesel-Fired Fire Pump (EU-015) – CO</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-0059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Fire Pump (EU-015)</b>	<b>500 HP</b>	<b>2.6 g/hp-hr, 3 hr average; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	2.6 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	3.5 g/KW-hr, avg. 3 tests; 0.45 ton/12 month rolling	Good Combustion Practices
MI-0389	Consumers Energy	12/29/09	Fire Pump	525 HP	2.6 g/hp-hr, test method	Good Design and Operation
LA-0254	Ninemile Point Electric Generating	08/16/11	Emergency Fire Pump	350 HP	2.6 g/HP-hr	Good Combustion Practices
FL-0322	Southeast Renewable Fuels	12/23/10	Emergency Diesel Fire Pump	600 HP	2.6 g/HP-hr	Comply with 40 CFR 60, Subpart IIII
SD-0005	Basin Electric Power Coop	10/14/11	Fire Pump	577 HP	None	40 CFR 60, Subpart IIII

### **RBLC Review**

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 2.6 g/hp-hr. The applicant is proposing essentially the same emission rate.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (1) CO emissions from the diesel-fired emergency fire pump (EU-015) shall be minimized by good combustion practices;
- (2) CO emissions shall not exceed 2.6 g/hp-hr; and
- (3) The diesel-fired emergency fire pump shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the diesel-fired fire pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency firewater pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (2) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall be controlled by the use of good combustion practices; and
- (3) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Fire Pump (EU-015) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Fire Pump (EU-015)</b>	<b>500 HP</b>	<b>0.141 g/hp-hr, 3 hr average; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	0.141 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	0.25 g/KW-hr, 3 run avg.; 0.03 ton/12 month rolling	Good Combustion
LA-0254	Entergy Louisiana	08/06/11	Emergency Fire Pump	350 HP	1 g/hp-hr, annual average	Good Combustion
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Fire Pump	500 HP	4 g/KW-hr; 100 hr/yr	Certified by manufacturer, 40 CFR 60, Subpart IIII
ID-0018	Idaho Power, Langley Gulch	06/25/10	Fire Pump Engine	235 KW	4 g/KW-hr	Tier 3 Engine, Good Combustion
OK-0129	Associated Electric Cooperative	01/23/09	Fire Pump	267 HP	0.66 lb/hr	Good Combustion

#### **RBLC Review**

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 0.14 g/hp-hr for the Ohio Valley Resources facility. The applicant is proposing essentially the same emission rate. The applicant's emission rate is 0.009 g/hp-hr higher. This equates to an additional 0.002 TPY of VOC on a slightly larger pump. This difference is insignificant. It should be noted that none of the emission units emitting VOC under 1.0 g/hp-hr have been constructed.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (1) Good combustion practices;
- (2) VOC emissions shall not exceed 0.141 g/hp-hr; and
- (3) The fire pump shall not operate more than 500 hours per year.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the diesel-fired fire pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA Diesel-Fired Fire Water Pump (EU-015) – Greenhouse Gases</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Fire Pump (EU-015)</b>	<b>500 HP</b>	<b>CO<sub>2</sub> – 527.40 g/hp-hr, 3 hr average; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump (EU-016)	481 HP	CO <sub>2</sub> – 527.40 g/hp-hr; 3 hr average; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	CO <sub>2</sub> e – 91 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, 3 test avg.; Methane – 0.0001 g/KW-hr, 3 test avg.	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Fire Pump	350 HP	CO <sub>2</sub> – 163 lb/MMBtu CH <sub>4</sub> – 0.0061 lb/MMBtu N <sub>2</sub> O – 0.0014 lb/MMBtu	Proper Operation and Good Combustion
MD-0040	CPV St Charles	11/12/08	Fire Water Pump	300 HP	Methane - 3 g/Hp-hr	None

#### **RBLC Review**

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 527.40 g/hp-hr as CO<sub>2</sub>. The applicant is proposing the same emission rate and control using good combustion practices. This is top BACT.

#### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr.



**Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency fire water pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Diesel-fired Emergency Fire Water Pump (EU-015)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency fire water pump (EU-015) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

**BACT Analysis – Emergency Raw Water Pump (EU-063)**

**Insignificant Activity**

- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063.  
[40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

**Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Emergency Raw Water Pump (EU-063) – PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Raw Water Pump (EU-063)</b>	<b>500 HP</b>	<b>PM, PM<sub>10</sub>, PM<sub>2.5</sub></b> 0.15 g/hp-hr, 3 hr avg., 500 hr/12 month rolling	<b>Good Combustion</b>
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	PM <sub>10</sub> 0.14 lb/hr max. 0.004 TPY max. 0.15 g/hp-hr 52 hr/yr	Good Design and Operating Practices
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	PM <sub>10</sub> -0.264 lb/hr 0.095 TPY	None

### **RBLC Review**

The raw water pump is used to supply water to the facility during emergencies. A review of the RBLC to find diesel-fired pumps in similar service shows two entries. Neither used add-on controls. One used good combustion practices to control particulate. The lowest emission rate is 0.15 g/hp-hr. This represents top BACT and is identical to the applicant's proposal.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (a) Good Combustion Practices;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions each shall each not exceed 0.15 g/hp-hr; and
- (c) Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Emergency Raw Water Pump (EU-063) – NO <sub>x</sub> BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	2.83 g/hp-hr, 3 hr avg. 500 hr/12 month rolling	Good Combustion
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	8.9 lb/hr max. 0.23 TPY max. 9.5 g/hp-hr	Good Design and Operation
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	3.17 lb/hr 1.34 TPY	None

#### **RBLC Review**

A review of the RBLC for raw water pumps indicates add-on controls are not used. Emissions are controlled by good combustion practices. The lowest emission rate is 9.5 g/hp-hr. The applicant is proposing an emission rate of 2.83 g/hp-hr controlled by good combustion practices. This represents top BACT.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Good Combustion Practices;
- (b) NO<sub>x</sub> emissions shall not exceed 2.83 g/hp-hr; and
- (c) Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (a) NO<sub>x</sub> from the diesel-fired emergency raw water pump (EU-063) emissions shall be controlled by good combustion practices;
- (b) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b> <b>Emergency Raw Water Pump (EU-063) – CO BACT</b>						
<b>RBL ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	1.88 lb/hr max; 0.05 TPY max; 2.01 g/hp-hr, annual average	Good Design and Operation
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Raw Water Pump (EU-063)</b>	<b>500 HP</b>	<b>2.60 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling</b>	<b>Good Combustion</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Water Pump	481 HP	2.60 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	3.5 g/KW-hr, avg. 3 tests; 0.45 ton/12 month rolling	Good Combustion Practices
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	0.8020 lb/hr, 0.2890 TPY	None

### **RBLC Review**

There are limited entries for small diesel-fired emergency raw water pumps. None of the entries use add-on control technology to control carbon monoxide emissions. The lowest entry in the RBLC table is 2.01 g/hp-hr for the pump installed at Crescent City Power. Carbon monoxide emissions from the Crescent City water pump are limited to 100 pounds of CO per year. This equates to 53 hours of operation. The next closest entry for a raw water pump in the table is the Structural Metals, Inc. raw water pump at 3.0 g/hp-hr. The applicant is proposing an emission rate of 2.60 g/hp-hr for a slightly larger unit. The 2.60 g/hp-hr limit is an NSPS Tier III compliant engine.

IDEM, OAQ does not believe Crescent City Power sets BACT for these units because the unit was never constructed and the PSD permit was revoked on November 1, 2006.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall be minimized by good combustion practices;
- (b) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr; and
- (c) The diesel-fired emergency raw water pump (EU-063) shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the diesel-fired emergency fire pump (EU-063) as:

- (a) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **VOC BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Emergency Raw Water Pump (EU-063) – VOC BACT</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	0.05 lb/hr max. 0.001 TPY max. 0.05 g/hp-hr, annual average	Good Design and Operation
<b>T 129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Raw Water Pump (EU-063)</b>	<b>500 HP</b>	<b>0.141 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling</b>	<b>Good Combustion</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Pump	481 HP	0.141 g/hp-hr, 3 hr avg.; 200 hr/yr	Good Combustion
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	0.2960 lb/hr 0.1070 TPY	None

**RBLC Review**

There are only two existing entries in the RBLC for diesel-fired pumps used in raw water service. The lowest emission rate is 0.05 g/hp-hr. The next lowest is 1.11 g/hp-hr. The applicant is proposing an emission rate of 0.15 g/hp-hr. IDEM, OAQ does not believe the Crescent City Power sets BACT for these units because the unit was never constructed and the PSD permit was revoked on November 1, 2006. Because of the limited entries in this category, IDEM, OAQ compared VOC BACT entries for small fire pumps, less than 500 HP.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall be minimized by good combustion practices;
- (b) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (c) The diesel-fired emergency raw water pump (EU-063) shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency fire pump (EU-063) as:

- (a) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **Greenhouse Gas BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA Emergency Raw Water Pump (EU-063) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Pump	481 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices, Use Limit
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	CO <sub>2</sub> e – 91 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, avg. 3 tests; Methane – 0.0001 g/KW-hr, avg. 3 tests	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Fire Pump	350 HP	CO <sub>2</sub> – 163 lb/MMBtu CH <sub>4</sub> – 0.0064 lb/MMBtu N <sub>2</sub> O – 0.0014 lb/MMBtu	Proper Operation and Good Combustion
MD-0040	CPV St Charles	11/12/08	Fire Pump	300 HP	Methane - 3 g/Hp-hr	None

#### RBLC Review

There are no RBLC entries for greenhouse gas emissions from small RICE engines in water service. IDEM, OAQ compared the proposed raw water pump to small fire water pumps. The lowest entry in this class is the Ohio Valley Resources (OVR) fire pump. The applicant has proposed the same emission rate. This is top BACT.

#### Applicant Proposal

The applicant has proposed the following as BACT:

- Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by the use of good combustion practices.
- CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

**Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency raw water pump (EU-063) as:

- (a) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by the use of good combustion practices.
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Emergency Raw Water Pump (EU-063)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for emergency raw water pump (EU-063) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

<b>BACT Analysis – Ten Cell Cooling Tower (EU-010)</b>
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**Insignificant Activity**

- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Emissions from cooling towers are generally controlled by a drift elimination system.

**Step 2: Eliminate Technically Infeasible Options**

(a) **High Efficiency Drift Eliminators**

Cooling towers are a source of particulate matter (PM/PM<sub>10</sub>/PM<sub>2.5</sub>) 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<sub>10</sub>/PM<sub>2.5</sub>) 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.

Drift eliminators contain packing which is used to limit the amount of 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.

The use of a drift elimination system is technically feasible control option for cooling tower (EU-010).

(b) **Dissolved Solids Management**

A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blow down) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blow down process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method for cooling tower (EU-010).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted both control strategies. Therefore, a ranking of control efficiencies is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Cooling Tower (EU-010) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-113	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-213	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-114	17,611 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
T147-30464-00060	Indiana Gasification	06/27/12	ASU and Main Cooling Tower EU-016A/B	55,000 GPM–A 405,000 GPM-B	0.0005% Drift 1,500 mg/l	High Efficiency Drift Eliminators
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Ten Cell Cooling Tower (EU-010)</b>	<b>147,937 GPM</b>	<b>0.0005% drift 2,000 mg/l TDS, monthly average</b>	<b>High Efficiency Drift Eliminators</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Cooling Towers EU-008A-H EU-019A-F	179,720 GPM combined	0.0005% Drift 2,000 mg/l TDS, daily average	High Efficiency Drift Eliminators
IA-0106	CF Industries, Port Neal	07/12/13	16 Cell Draft Cooling Tower	322,000 GPM	0.0005% drift 2,030 mg/l TSD	High Efficiency Drift Eliminators

#### **RBLC Review**

All of the entries in the RBLC for cooling towers indicates high efficiency drift eliminators are the only commercially viable particulate control method used today. All of the entries have limited emissions by setting a maximum allowable drift of 0.0005%. It is less clear that a limit on the total dissolved solids (TSD) concentration is expected for the cooling water. The lowest entries in the RBLC are all from the same source using the same water supply. The Nucor plant is required to achieve a maximum drift of 0.0005% with a maximum TDS of 1,000 mg/liter.

IDEM, OAQ does not believe the Nucor cooling tower or the Indiana Gasification (IG) cooling tower sets particulate BACT for Midwest Fertilizer Corporation (MFC). To start, the cooling towers at Nucor are much smaller than the units proposed by MFC. The MCF towers will use well water while the IG cooling towers use river water. River water is naturally lower in dissolved solids than well water. Ground water travels slowly from the recharge point to the well and the water is in direct contact with the ions that contribute to TDS. These ions include chloride, sodium, nitrate, calcium, magnesium, bicarbonate, sulfate, boron, bromide and iron. A higher TSD for Ohio Valley Resources and Midwest Fertilizer Corporation is justified.

The most recent RBLC entries use a maximum 0.0005% drift and a TDS concentration of 2,000 mg/liter.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for cooling tower (EU-010) as:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The cooling tower identified as EU-010 does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the cooling tower for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Ten Cell Cooling Tower (EU-010)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for ten cell cooling tower (EU-010) shall be as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (2) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

<b>BACT Analysis – Six Cell Cooling Tower (EU-011)</b>
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### **Insignificant Activity**

- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]

## **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

Emissions from cooling towers are generally controlled by a drift elimination system.

### **Step 2: Eliminate Technically Infeasible Options**

#### **(a) High Efficiency Drift Eliminators**

Cooling towers are a source of particulate matter (PM/PM<sub>10</sub>/PM<sub>2.5</sub>) 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<sub>10</sub>/PM<sub>2.5</sub>) 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.

Drift eliminators contain packing which is used to limit the amount of 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.

The use of a drift elimination system is technically feasible control option for cooling tower (EU-011).

#### **(b) Dissolved Solids Management**

A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blow down) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blow down process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method for cooling tower (EU-011).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted both control strategies. Therefore, a ranking of control efficiencies is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Cooling Tower (EU-011) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-113	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.11 lb/hr PM <sub>10</sub> -0.4 TPY	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-213	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.11 lb/hr PM <sub>10</sub> -0.4 TPY	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-114	17,611 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.07 lb/hr PM <sub>10</sub> -0.29 TPY	Drift Eliminators
T147-30464-00060	Indiana Gasification	06/27/12	ASU and Main Cooling Tower EU-016A/B	55,000 GPM-A 405,000 GPM-B	0.0005% Drift 1,500 mg/l, daily average	High Efficiency Drift Eliminators
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Six Cell Cooling Tower (EU-011)</b>	<b>147,937 GPM</b>	<b>0.0005% drift 2,000 mg/l TDS, monthly average</b>	<b>High Efficiency Drift Eliminators</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Cooling Towers EU-008A-H EU-019A-F	179,720 GPM combined	0.0005% Drift 2,000 mg/l TDS, daily average	High Efficiency Drift Eliminators
IA-0106	CF Industries, Port Neal	07/12/13	16 Cell Draft Cooling Tower	322,000 GPM	0.0005% drift 2,030 mg/l TDS	High Efficiency Drift Eliminators

#### **RBLC Review**

All of the entries in the RBLC for cooling towers indicates high efficiency drift eliminators are the only commercially viable particulate control method used today. All of the entries have limited emissions by setting a maximum allowable drift of 0.0005%. It is less clear that a total dissolved solids (TSD) concentration is expected for the cooling water. The lowest entries in the RBLC are all from the same source using the same water supply. The Nucor plant is required to achieve a maximum drift of 0.0005% with a maximum TDS of 1,000 mg/liter.

IDEM, OAQ does not believe the Nucor cooling tower or the Indiana Gasification (IG) cooling tower sets particulate BACT for Midwest Fertilizer Corporation (MFC). To start, the cooling towers at Nucor are much smaller than the units proposed by MFC. The MFC towers will use well water while the IG cooling towers use river water. River water is naturally lower in dissolved solids than well water. Ground water travels slowly from the recharge point and the water is in direct contact with the ions that contribute to TDS. These ions include chloride, sodium, nitrate, calcium, magnesium, bicarbonate, sulfate, boron, bromide and iron. A higher TSD for Ohio Valley Resources and Midwest Fertilizer Corporation is justified. The most recent RBLC entries use a maximum 0.0005% drift and a TDS concentration of 2,000 mg/liter.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for cooling tower (EU-011) as:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The cooling tower identified as EU-011 does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the cooling tower for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Six Cell Cooling Tower (EU-011)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the six cell cooling tower (EU-011) shall be as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (2) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

<b>BACT Analysis – Distillate Oil Storage Tank (EU-066)</b>
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### **Insignificant Activity**

- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]

### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gas (GHG) emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for these pollutants and BACT analyses are not required for these pollutants.



### **VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions will be less than 0.01 tons per year. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Nitric Acid Storage Tank (EU-054)**

#### **Insignificant Activity**

- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tanks do not contain an organic liquid. [326 IAC 2-2]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid storage tank for these pollutants and BACT analyses are not required for these pollutants.

#### **NO<sub>x</sub> and VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Urea Ammonium Nitrate Storage Tanks (EU-034, EU-035, and EU-036)**

#### **Insignificant Activity**

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea ammonium nitrate (UAN) storage tanks for these pollutants and BACT analyses are not required for these pollutants.

#### **NO<sub>x</sub> and VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from these units as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>BACT Analysis – Diesel Exhaust Fluid Tank (EU-037)</b>
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**Insignificant Activity**

- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the diesel exhaust fluid (DEF) storage tank for these pollutants and BACT analyses are not required for these pollutants.

**VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>BACT Analysis – OASE<sup>®</sup> Solution / Methyldiethanolamine (MDEA) Storage Tank (EU-043)</b>
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**Insignificant Activity**

- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to this unit for these pollutants and BACT analyses are not required for these pollutants.

**VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>BACT Analysis – Paved Roads and Parking Lots</b>
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**Insignificant Activity**

- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and PM<sub>2.5</sub> from fugitive sources are generally controlled with measures to prevent the emissions from occurring. Generally, fugitive PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from roadways are controlled through one of the following mechanisms:

- (1) Paving of Roadways;
- (2) Wet Suppression or Chemical suppression; and
- (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**

(a) **Add-on Control Technology:**

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. The use of add-on controls is not a technically feasible control option for the paved roadways and parking lots with public access.

(b) **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 affecting the degree of agglomeration and 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 a water/surfactant mix and foams. Wet suppression systems typically achieve PM control efficiencies of greater than 85%. The use of a wet suppression or chemical suppression is a technically feasible control option for the paved roadways and parking lots with public access.

(c) **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. The use of paving roadways and good housekeeping is a technically feasible control option for the paved roadways and parking lots with public access.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been proposed by the applicant for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the paved roadways and parking lots with public access:

- (a) Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.
- (b) Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

The applicant has accepted all control technologies. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Paved Roadways and Parking Lots with Public Access – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Paved Roads and Parking Lots</b>	<b>10,403 VMT/yr</b>	<b>90% Control</b>	<b>Paving, Speed Limits, sweeping, wet suppression</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Paved Roads and Parking Lots	17,160 VMT/yr	90% Control	Paving, Speed Limits, sweeping, wet suppression
T147-30464-00060	Indiana Gasification	06/27/12	Haul Roads	Not indicated	90% Control	Paving, wet suppression, prompt cleanup
OH-0317	Ohio River Clean Fuels	11/20/08	Paved Roads	736,205 VMT/yr	PM – 79.00 TPY PM <sub>10</sub> – 15.69 TPY 90% Control	Watering, Sweeping, Speed Limit
OH-0297	FDS Coke Company	06/14/04	Roadways	Unknown	PM – 24.88 TPY PM <sub>10</sub> – 4.85 TPY	Watering
OH-0328	V & M Star	04/10/09	Roadways	Unknown	PM <sub>10</sub> – 12.4 TPY (AP-42 Emission Factors)	Control Measures to Minimize Emissions
IA-0105	Iowa Fertilizer Company	10/26/12	Paved Roads	2 miles of road	No numeric limit	Water Flushing, Sweeping

#### **RBLC Review**

The table above shows recent entries in the RACT/BACT/LEAR Clearinghouse (RBLC database for haul roads. Control measures include watering, sweeping, speed limits and good housekeeping. The highest emission reduction appearing in the RBLC is 90% control.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) All roadways will be paved;
- (b) The source will use speed limits; and
- (c) The source will use daily sweeping with wet suppression.

### **Step 5: Select BACT**

The PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (1) Paving all plant haul roads;
- (2) Daily sweeping with wet suppression; and
- (3) Prompt cleanup of any spilled materials.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

Fugitive emissions from paved roads and parking lots will not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to paved roads and parking lots for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Paved Roads and Parking Areas</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for paved roads and parking areas shall be as follows:

PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (1) Paving all plant haul roads;
- (2) Daily sweeping with wet suppression; and
- (3) Prompt cleanup of any spilled materials.

**Indiana Department of Environmental Management  
Office of Air Quality**

**Technical Support Document (TSD) for a  
PSD/New Source Construction and Part 70 Operating Permit**

<b>Source Description and Location</b>
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Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873 (Nitrogenous Fertilizers)
Operation Permit No.:	T 129-33576-00059
Permit Reviewer:	David Matousek

On August 26, 2013, Midwest Fertilizer Corporation submitted an application for a PSD/New Source Review and Part 70 Operating Permit for a stationary nitrogen fertilizer manufacturing facility. The facility will be located in the southeast quadrant of the intersection of Old SR 69 and Mackey Ferry Road East in Mt. Vernon, Posey County, Indiana. The proposed facility will produce anhydrous ammonia, nitric acid, liquid urea, granulated urea, urea ammonium nitrate (28 to 32% nitrogen content), and diesel exhaust fluid (32.5% urea solution). The final products will be shipped from the facility using truck and rail transport.

<b>Existing Approvals</b>
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There have been no previous approvals issued to this source.

<b>County Attainment Status</b>
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The source is located in Posey County.

Pollutant	Designation
SO <sub>2</sub>	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O <sub>3</sub>	Unclassifiable or attainment effective July 20, 2012 for the 2008 8-hour ozone standard <sup>1</sup>
PM <sub>2.5</sub>	Unclassifiable or attainment effective April 5, 2005, for the annual PM <sub>2.5</sub> standard.
PM <sub>2.5</sub>	Unclassifiable or attainment effective December 13, 2009, for the 24-hr PM <sub>2.5</sub> standard.
PM <sub>10</sub>	Unclassifiable effective November 15, 1990.
NO <sub>2</sub>	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.
<sup>1</sup> 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 (NO<sub>x</sub>) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO<sub>x</sub> emissions are considered when evaluating the rule applicability relating to ozone. Posey County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO<sub>x</sub> emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) **PM<sub>2.5</sub>**

Posey County has been classified as attainment for PM<sub>2.5</sub>. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for PM<sub>2.5</sub> 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<sub>2.5</sub> significant level at ten (10) tons per year. This rule became effective June 28, 2011. Therefore, direct PM<sub>2.5</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) **Other Criteria Pollutants**

Posey County has been classified as attainment or unclassifiable in Indiana for CO, PM<sub>10</sub>, NO<sub>x</sub>, and lead. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

<b>Fugitive Emissions</b>
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Since this source is classified as a chemical process plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

<b>Permitted Emission Units and Pollution Control Equipment</b>
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(a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:

(1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.

(2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.

(b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.

(c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.

- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.
- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]
- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.
- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> is controlled by a Selective Catalytic Reduction Unit, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]
- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively. [40 CFR 60, Subpart KKKK]
- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]
- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1. [40 CFR 60, Subpart VVa]
- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.
- (l) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-021A.
- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

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

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]
- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]



- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]
- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]
- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]
- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]
- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tank does not contain an organic liquid. [326 IAC 2-2]
- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2] [40 CFR 60, Subpart VVa]
- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]
- (bb) Two (2) ammonia storage tanks, identified as EU-032 and EU-033, approved for construction in 2014, each with a maximum capacity of 30,000 metric tons, using Ammonia Storage Flare EU-016 for emissions control, exhausting to stack S-016. The tanks do not contain an organic liquid. [326 IAC 2-2]

### Enforcement Issues

There are no pending enforcement actions.

### Stack Summary

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (°F)
001	Reformer	175	11.93	335,353	325.13
002	Startup Heater	112	6.5	97,359	1,649.93
003	CO <sub>2</sub> Purification	202	2.17	46,755	125
008	Urea Granulation	215	8	208,100	104
009	Nitric Acid Plant	215	8	206,820	258.89
010A to J	Cooling Tower EU-010	99	35	726,204	104
011A to F	Cooling Tower EU-011	99	35	726,204	104.63
012A to C	Auxiliary Boiler	135	6	55,983	350.33
013A and B	Combustion Turbine	125	15	525,904	330.53
014	Generator	50	1.75	18,372	920.93
015	Fire Water Pump	50	0.67	2,935	899.33
016	Ammonia Flare	150	2.62	47.55	1,999
016_SSM	Ammonia Flare SSM	150	2.62	4,231	1,999
017	Front End Flare	150	7.33	53.17	1,999
017_SSM	Front End Flare SSM	150	7.33	368,698	1,832
018	Back End Flare	150	5.5	74.13	1,999
018_SSM	Back End Flare SSM	150	5.5	451,228	1,832
020	Truck Loading Operation	95	1.5	4,602	70
021A	Rail Loading Operation	75	2	7,992	70
021B	Urea Junction Operation	75	1.5	7,992	70
024	Urea Warehouse	115	1.5	6,500	70
063	Raw Water Pump	50	0.67	2,935	899.33
054	Nitric Acid Tank	82.38	1.5	6.89	122

### Emission Calculations

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

### Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source.

Unrestricted Potential Emissions	
Pollutant	Ton/year
PM	555.67
PM <sub>10</sub>	598.16
PM <sub>2.5</sub>	594.40
SO <sub>2</sub>	7.88
VOC	109.97
CO	1,079
NO <sub>x</sub>	1,796.54
GHGs as CO <sub>2</sub> e	4,023,910
Single HAP	13.21 – Hexane
Total HAP	25.64

Appendix A of this TSD reflects the unrestricted potential emissions of the source.

- (a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, CO and NO<sub>x</sub> 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<sub>2</sub> equivalent emissions (CO<sub>2</sub>e) 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 any single HAP is equal to or greater than ten (10) tons per year and/or the potential to emit (as defined in 326 IAC 2-7-1(29)) of a combination of HAPs is equal to or greater than twenty-five (25) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

#### Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

- (a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.
- (b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

#### Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit renewal, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM <sub>10</sub> *	PM <sub>2.5</sub> **	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	GHGs as CO <sub>2</sub> e	Total HAPs	Hexane
Reformer Furnace	7.76	21.98	21.98	2.45	45.50	22.45	177.37	487,152	7.70	9.83
Startup Heater	0.017	0.069	0.069	0.005	1.67	0.05	0.34	1,082	0.02	
Aux. Boiler #1	1.43	5.71	5.71	0.45	9.19	4.13	27.95	89,617	1.42	
Aux. Boiler #2	1.43	5.71	5.71	0.45	9.19	4.13	27.95	89,617	1.42	
Aux. Boiler #3	1.43	5.71	5.71	0.45	9.19	4.13	27.95	89,617	1.42	
CO <sub>2</sub> Purification	0.00	0.00	0.00	0.00	0.00	26.95	5.65	1,232,475	8.98	0.00
Front End Flare	0.03	0.13	0.13	0.01	1.19	0.09	6.48	2,050	0.03	0.03
Back End Flare	0.03	0.13	0.13	0.01	1.19	0.09	6.48	2,050	0.03	0.03

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM <sub>10</sub> *	PM <sub>2.5</sub> **	SO <sub>2</sub>	NO <sub>x</sub>	VOC	CO	GHGs as CO <sub>2</sub> e	Total HAPs	Hexane
Ammonia Flare	0.01	0.05	0.05	0.004	0.45	0.04	2.43	769	0.01	0.01
Urea Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation	47.21	47.21	47.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Urea Storage	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitric Acid Plant	0.00	0.00	0.00	0.00	23.69	0.00	0.00	70,370	0.00	0.00
Turbine EU-013A	2.36	9.42	9.42	1.74	103.43	8.68	37.19	145,032	1.24	0.00
Turbine EU-013B	2.36	9.42	9.42	1.74	103.43	8.68	37.19	145,032	1.24	0.00
Generator	0.30	0.30	0.30	0.01	8.85	0.62	5.18	1,048	0.01	0.00
Fire Pump	0.04	0.04	0.04	1.37E-03	0.78	0.04	0.72	146	3.41E-03	0.00
Raw Water Pump	0.04	0.04	0.04	1.37E-03	0.78	0.04	0.72	146	3.41E-03	0.00
Cooling Tower 11	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower 10	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fugitive Leaks	0.00	0.00	0.00	0.00	0.01	14.39	0.07	1,215	0.01	0.00
Paved Roads	0.32	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage Tanks	0.00	0.00	0.00	0.00	0.13	2E-03	0.00	0.00	0.00	0.00
Truck Loading	0.53	0.53	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rail Loading	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Urea Junction	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Urea Warehouse	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SSM Emissions	0.00	0.00	0.00	0.00	215.53	9.91	679.55	214,890	0.00	0.00
PTE of Entire Source	73.77	113.10	109.77	7.31	534.20	104.41	1,043	2,573,349	23.53	9.90
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO <sub>2</sub> e	25	10
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000 CO <sub>2</sub> e	NA	NA

negl. = negligible; \* Under the Part 70 Permit program (40 CFR 70), PM<sub>10</sub> and PM<sub>2.5</sub>, not particulate matter (PM), are each considered as a regulated air pollutant"; \*\*PM<sub>2.5</sub> listed is direct PM<sub>2.5</sub>.

- (a) This stationary source is major for PSD because the emissions of at least one criteria pollutant is greater than one hundred (>100) tons per year and it is in one of the twenty-eight (28) listed source categories.
- (b) GHG emissions are equal to or greater than one hundred thousand (>100,000) tons of CO<sub>2</sub> equivalent (CO<sub>2</sub>e) emissions per year.

<b>Federal Rule Applicability</b>
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**NSPS**

- (a) **40 CFR 60, Subpart D – Standards of Performance for Fossil Fuel-Fired Steam Generators:** This subpart applies to fossil fuel-fired steam generators for which construction or modification commenced after August 17, 1971 and with a firing capacity of greater than 250 MMBtu/hr. A fossil fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer. The proposed reformer and both combustion turbines have a heat input capacity of greater than 250 MMBtu/hr and will be constructed after August 17, 1971. However, the reformer is not a steam-generating unit. The combustion turbines are exempt from Subpart D, pursuant to 40 CFR 60.40(e), because they are subject to 40 CFR Subpart KKKK (Standards of Performance for Stationary Combustion Turbines).
- (b) **40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units:** This subpart applies to each electric utility steam generating unit that is capable of combusting 250 MMBtu/hr or more of fossil fuel, for which construction, modification, or reconstruction commenced after September 18, 1978. This rule also applies to non-electric utility steam generating units, such as heat recovery steam generators associated with a stationary combustion turbine, unless the units are subject to NSPS Subpart GG or NSPS Subpart KKKK. The combustion turbines are exempt from Subpart Da, pursuant to 40 CFR 60.40Da(e)(1), because they are subject to 40 CFR 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines). The reformer furnace (EU-001) is a process heater and not a steam generating unit. Therefore, it is not subject to 40 CFR 60, Subpart Da.
- (c) **40 CFR, 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units:** The three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, each with heat input capacities of 218.6 MMBtu/hr, are subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Db) which is incorporated by reference as 326 IAC 12. These steam generating units will commence construction after June 19, 1984, and have a maximum design heat input capacity of 100 MMBtu/hr or greater. Therefore, this subpart applies to the natural gas-fired auxiliary boilers. While this rule applies to the auxiliary boilers, the rule does not apply to the heat recovery steam generators used with a stationary combustion turbine are exempt from the subpart, pursuant to 40 CFR 60.40b(i).

Nonapplicable portions of the NSPS will not be included in the permit. All three natural gas-fired auxiliary boilers (EU-012A/B/C) are subject to the following portions of Subpart Db:

- (1) 40 CFR 60.42b(k)(2);
- (2) 40 CFR 60.44b(h) and (i);
- (3) 40 CFR 60.44b(l);
- (4) 40 CFR 60.46b(a);
- (5) 40 CFR 60.46b(c);

- (6) 40 CFR 60.46b(e);
- (7) 40 CFR 60.48b(b) to (f);
- (8) 40 CFR 60.49b(a) and (b);
- (9) 40 CFR 60.49b(d);
- (10) 40 CFR 60.49b(g);
- (11) 40 CFR 60.49b(i); and
- (12) 40 CFR 60.49b(o).

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the natural gas fired boilers, identified as emission units EU-012A, EU-012B, and EU-012C, except when otherwise specified in 40 CFR 60, Subpart Db.

- (d) **40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units:** This rule applies 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 100 MMBtu/hr or less, but greater than 10 MMBtu/hr. The natural gas-fired reformer furnace (EU-001) is not a steam generating unit; therefore, this rule does not apply to the reformer furnace. The auxiliary boilers are steam generating units; however, their heat input capacity is greater than 100 MMBtu/hr; therefore this rule does not apply to the natural gas-fired auxiliary boilers (EU-012A/B/C).
- (e) **40 CFR 60, Subpart G – Standards of Performance for Nitric Acid Plants:** This subpart applies to each nitric acid production unit for which construction or modification occurs after August 17, 1971 and before October 14, 2011. The nitric acid units at this source will be constructed after October 14, 2011. Therefore, this subpart does not apply to any of the nitric acid units located at this source.
- (f) **40 CFR 60, Subpart Ga – Standards of Performance for Nitric Acid Plants for which Construction, Reconstruction, or Modification Commences after October 14, 2011:** The nitric acid plant, identified as EU-009, is subject to the Standards of Performance for Nitric Acid Plants for which Construction, Reconstruction, or Modification Commenced after October 14, 2011 (40 CFR 60.70a, Subpart Ga), which is incorporated by reference as 326 IAC 12. The provisions of this subpart apply to each nitric acid production unit that commences construction after October 14, 2011. A nitric acid production unit is defined as any facility producing weak nitric acid by either the pressure or atmospheric process. This facility contains a nitric acid production unit. Therefore, this subpart applies.

Nonapplicable portions of the NSPS will not be included in the permit. The nitric acid plant (EU-009) is subject to the following portions of Subpart Ga:

- (1) 40 CFR 60.70a;
- (2) 40 CFR 60.72a;
- (3) 40 CFR 60.73a;
- (4) 40 CFR 60.74a;
- (5) 40 CFR 60.75a;
- (6) 40 CFR 60.76a; and
- (7) 40 CFR 60.77a.

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the nitric acid plant, identified as EU-009, except when otherwise specified in 40 CFR 60, Subpart Ga.

- (g) **40 CFR 60, Subpart K – Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after June 11, 1973, and Prior to May 19, 1978:** The storage vessels located at this source will be constructed after May 19, 1978. Therefore, this subpart does not apply to any of the storage tanks located at this source.
- (h) **40 CFR 60, Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after May 18, 1978 and Prior to July 23, 1984:** The storage vessels located at this source will be constructed after July 23, 1984. Therefore, this subpart does not apply to any of the storage tanks located at this source.
- (i) **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:** This subpart applies to each storage vessel with a capacity greater than or equal to 19,812 gallons that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. This rule does not apply to storage vessels with a capacity greater than or equal to 39,890 gallons used to store a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 19,812 gallons but less than 39,890 gallons storing a liquid with a maximum true vapor pressure less than 15 kPa. The nitric acid and ammonia storage tanks do not contain an organic liquid. The distillate oil tank is less than 19,812 gallons. The urea ammonium nitrate, diesel exhaust fluid, and the OASE<sup>®</sup> solution / Methyl-diethanolamine (MDEA) storage tanks all store organic liquids with vapor pressures less than 3.5 kPa. Therefore, this subpart does not apply.
- (j) **40 CFR 60, Subpart T – Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants:** This subpart applies to each wet-process phosphoric acid plant having a design capacity of more than 15 tons of equivalent phosphorus pentoxide feed per calendar day. All reactors, filters, evaporators and hot wells constructed after October 22, 1974 are subject. Midwest Fertilizer Corporation does not operate a wet-process phosphoric acid plant. Therefore, this subpart does not apply.
- (k) **40 CFR 60, Subpart U – Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Plants:** This subpart applies to each superphosphoric acid plant having a design capacity of more than 15 tons of equivalent phosphorus pentoxide feed per calendar day. All evaporators, hot wells, acid pumps, and cooling tanks constructed after October 22, 1974 is subject. Midwest Fertilizer Corporation does not operate a superphosphoric acid plant. Therefore, this subpart does not apply.
- (l) **40 CFR 60, Subpart V – Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants:** This subpart applies to each diammonium phosphate plant have a design capacity of more than 15 tons of equivalent phosphorus pentoxide feed per calendar day. All reactors, granulators, dryers, coolers, screens, and mills constructed after October 22, 1974 are subject. Midwest Fertilizer Corporation does not operate a diammonium phosphate plant. Therefore, this subpart does not apply.
- (m) **40 CFR 60, Subpart W – Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants:** This subpart applies to each triple superphosphate plant having a design capacity of more than 15 tons or equivalent phosphorus pentoxide feed per calendar day. All mixers, curing belts (dens), reactors, granulators, dryers, cookers, screens, mills, and facilities which store run-of-pile superphosphate constructed after October 22, 1974. Midwest Fertilizer Corporation does not operate a triple superphosphate plant. Therefore, this subpart does not apply.

- (n) **40 CFR 60, Subpart X – Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities:** This rule applies to each granular triple superphosphate storage facility. All storage or curing piles, conveyors, elevators, screens and mills constructed after October 22, 1974 are subject. Midwest Fertilizer Corporation does not operate a granular triple superphosphate plant. Therefore, this subpart does not apply.
- (o) **40 CFR 60, Subpart GG – Standards of Performance for Stationary Gas Turbines:** This subpart applies to all stationary gas turbines with a heat input capacity at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel, that commenced construction, modification, or reconstruction after October 3, 1977. Pursuant to 40 CFR 60.4305(b), stationary combustion turbines regulated under 40 CFR 60, Subpart KKKK are exempt from the requirements of Subpart GG. The combustion turbines at this source are subject to Subpart KKKK. Therefore, this subpart does not apply.
- (p) **40 CFR 60, Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced after January 5, 1981, and on or before November 7, 2006:** This subpart applies to affected facilities in the synthetic organic chemicals manufacturing industry that commenced construction, reconstruction, or modification after January 5, 1981 and on or before November 7, 2006. This facility will be constructed after the applicability date of this subpart. Therefore, this subpart does not apply.
- (q) **40 CFR 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction or Modification Commenced after November 7, 2006:** The Urea Synthesis Plant, identified as EU-006, the Urea Ammonium Nitrate Plant, identified as EU-007, the Urea Granulation Unit, identified as EU-008, the Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, and all fugitive emissions from equipment leaks, identified as F-1, are subject to the Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commences after November 7, 2006 (40 CFR 60.480a, Subpart VVa), which is incorporated by reference as 326 IAC 12. The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry, which commenced construction, reconstruction, or modification after November 7, 2006, and processes raw materials, or produces an intermediate or final product of a chemical compound listed in 40 CFR 60.489. Urea is a listed chemical and is produced as a final product and used as an intermediate at this facility. Therefore, this subpart applies.

Nonapplicable portions of the NSPS will not be included in the permit. The Urea Synthesis Plant, identified as EU-006, the Urea Ammonium Nitrate Plant, identified as EU-007, the Urea Granulation Unit, identified as EU-008, the Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, and all fugitive emissions from equipment leaks, identified as F-1 are subject to the following portions of Subpart VVa:

- (1) 40 CFR 60.480a(a) to (c);
- (2) 40 CFR 60.480a(d)(1) and (d)(3); and
- (3) 40 CFR 60.486a(a)(1), (i), (j), and (k).

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the Urea Synthesis Plant, identified as EU-006, the Urea Ammonium Nitrate Plant, identified as EU-007, the Urea Granulation Unit, identified



as EU-008, the Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, and all fugitive emissions from equipment leaks, identified as F-1, except when otherwise specified in 40 CFR 60, Subpart VVa.

- (r) **40 CFR 60, Subpart III – Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes:** This subpart applies air oxidation reactors constructed after October 21, 1983 that manufacture a chemical listed in 40 CFR 60.617. This facility does not contain any air oxidation unit processes or manufacture a listed chemical. Therefore, this subpart does not apply.
- (s) **40 CFR 60, Subpart NNN – Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations:** This subpart applies to distillation operations where a listed chemical is produced as a product, co-product, by-product, or intermediate. This facility will not produce any of the chemical compounds listed in 40 CFR 60.667. Therefore, this subpart does not apply.
- (t) **40 CFR, Subpart RRR – Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes:** This subpart applies to reactor operations where a listed chemical is produced as a product, co-product, by-product, or intermediate. This facility will not produce any of the chemical compounds listed in 40 CFR 60.707. Therefore, this subpart does not apply.
- (u) **40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines:** One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, one (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, one (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063 are subject to the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60.4200, Subpart IIII), which is incorporated by reference as 326 IAC 12. The provisions of this subpart are applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction, after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 and are not fire pumps, or manufactured as a certified National Fire Protection Association fire pump after July 1, 2006. The provisions of this subpart also applies to owners and operators of any stationary CI ICE that is modified or reconstructed after July 11, 2005, and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005. The generator and raw water pump are subject to this subpart because they are not fire pumps and will be constructed after April 1, 2006. The fire water pump is subject to this subpart because it is a certified fire pump engine and will be constructed after July 1, 2006. Nonapplicable portions of the NSPS will not be incorporated into the permit.

The emergency generator (3,600 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(i);
- (2) 40 CFR 60.4205(b);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c), and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.

The emergency fire water pump (500 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(ii);
- (2) 40 CFR 60.4205(c);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c), and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.

The emergency raw water pump (500 HP) is subject to the following portions of Subpart IIII:

- (1) 40 CFR 60.4200(a)(2)(i);
- (2) 40 CFR 60.4205(b);
- (3) 40 CFR 60.4206;
- (4) 40 CFR 60.4207(b);
- (5) 40 CFR 60.4208;
- (6) 40 CFR 60.4209(a);
- (7) 40 CFR 60.4211(a), (c) and (f);
- (8) 40 CFR 60.4214(b); and
- (9) 40 CFR 60.4218.

- (v) **40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines:** This subpart applies to stationary spark ignition internal combustion engines as specified in the subpart. The fire water pump, emergency generator and raw water pump are compression ignition and not spark ignition. Therefore, this subpart does not apply.

- (w) **40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines:** Two (2) natural gas-fired open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, each with a maximum heat input capacity of 283 MMBtu/hr are subject to the Standards of Performance for Stationary Combustion Turbines (40 CFR 60.4300, Subpart KKKK), which is incorporated by reference as 326 IAC 12. The provisions of this subpart are applicable to owners and operators of stationary combustion turbines with a heat input at peak load equal to or greater to 10 MMBtu/hr, based on the higher heating value of the fuel, which commence construction, modification, or reconstruction after February 18, 2005. The open-simple cycle combustion turbines located at this facility will be constructed after February 18, 2005 and have a heat input capacity greater than 10 MMBtu/hr. Therefore, this subpart applies.

Nonapplicable portions of the NSPS will not be incorporated into the permit. The natural gas-fired open-simple cycle combustion turbines are subject to the following portions of Subpart KKKK:

- (1) 40 CFR 60.4300;
- (2) 40 CFR 60.4305;
- (3) 40 CFR 60.4315;
- (4) 40 CFR 60.4320(a);
- (5) 40 CFR 60.4330(a)(2);
- (6) 40 CFR 60.4333;
- (7) 40 CFR 60.4335(b);
- (8) 40 CFR 60.4345;
- (9) 40 CFR 60.4350(f)(2) and (h);

- (10) 40 CFR 60.4355;
- (11) 40 CFR 60.4365(a);
- (12) 40 CFR 60.4375(a);
- (13) 40 CFR 60.4380(b);
- (14) 40 CFR 60.4395;
- (15) 40 CFR 60.4405;
- (16) 40 CFR 60.4410; and
- (17) 40 CFR 60.4420.

## NESHAP

- (a) **40 CFR 61, Subpart V – National Emissions Standards for Equipment Leaks:** This subpart applies to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems identified in the subpart that operate in volatile hazardous air pollutant (VHAP) service. A VHAP means a substance regulated under Part 61 for which a standard for equipment leaks of the substance has been proposed or promulgated. For a unit to be considered in VHAP service, there must be a reasonable possibility that a VHAP content in the material processed exceeds 10% by weight. All units of the type regulated under this subpart do not operate in VHAP service. Therefore, this subpart does not apply.
- (b) **40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j):** This facility is not a major source of Hazardous Air Pollutants. Therefore, this subpart does not apply.
- (c) **40 CFR 63, Subparts F, G, and H – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry:** These subpart do not apply to this facility because the source will not manufacture or produce any of the chemicals listed in Table 1 of 40 CFR 63, Subpart F, Table 1.
- (d) **40 CFR 63, Subpart Q – National Emission Standards for Hazardous Air Pollutants for Industrial Cooling Towers:** This subpart does not apply because the source will not use chromium based materials in its cooling towers.
- (e) **40 CFR 63, Subpart BB – National Emission Standards for Hazardous Air Pollutant from Phosphate Fertilizer Production Plants:** This subpart does not apply because the source will not product phosphate based fertilizers. It will manufacture nitrogen based fertilizers.
- (f) **40 CFR 61, Subpart FF – National Emission Standards for Benzene Waste Operations:** The entire source is subject to the National Emission Standards for Benzene Waste Operations (40 CFR 61.340, Subpart FF). The entire source is subject to the following portions of 40 CFR 61, Subpart FF:
  - (1) 40 CFR 61.340(a) and (c);
  - (2) 40 CFR 61.341;
  - (3) 40 CFR 61.342(a);
  - (4) 40 CFR 61.355;
  - (5) 40 CFR 61.356; and
  - (6) 40 CFR 61.357(a) and (b).

The provisions of 40 CFR 61, Subpart A – General Provisions, which are incorporated as 326 IAC 14-1, apply to the entire source as described in this section except when otherwise specified in 40 CFR 61, Subpart FF.

- (g) **40 CFR 63, Subparts OO and PP – National Emission Standards for Tanks and Containers:** These rules apply to storage and containers when another NSPS or NESHAP standard that is applicable to the source refers to these subparts. This source is not subject to any NSPS or NESHAP that references these subparts. Therefore, they do not apply.
- (h) **40 CFR 63, Subpart EEEE – National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline):** This subpart applies to emissions of Hazardous Air Pollutants from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions. This source does not distribute organic liquids containing HAPs and it is an area source of HAPs. Therefore, this subpart does not apply.
- (i) **40 CFR 63, Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing:** This subpart applies to miscellaneous organic chemical manufacturing process units located at major sources of hazardous air pollutants that produce a listed organic chemical. This source produces an organic chemical under SIC 287 which is a listed chemical. However, it is located at an area source of HAPs. Therefore, this rule does not apply.
- (j) **40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines:** This subpart applies to hazardous air pollutant emissions from stationary combustion turbines located at major sources of HAP emissions. This source has two stationary combustion turbines; however, it is an area source of HAPs. Therefore, this rule does not apply.
- (k) **40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:** The distillate oil-fired emergency generator, identified as emission unit EU-014, the distillate oil-fired emergency fire water pump, identified as emission unit EU-015, and the distillate oil-fired emergency raw water pump, identified as emission unit EU-063, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR 63.6580, Subpart ZZZZ), which is incorporated by reference as 326 IAC 20-82. This subpart applies to stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. The raw water pump, fire water pump and emergency generator are RICE located at an area source of HAPs. Therefore, this subpart applies. The units subject to Subpart ZZZZ are listed below:
  - (1) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
  - (2) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
  - (3) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

The emergency generator, emergency fire water pump, and the emergency raw water pump are subject to the following portions of Subpart ZZZZ:

- (1) 40 CFR 63.6585(c);
- (2) 40 CFR 63.6590(a)(2)(iii);
- (3) 40 CFR 63.6590(c)(1);
- (4) 40 CFR 63.6595(a)(7);
- (5) 40 CFR 63.6670; and
- (6) 40 CFR 63.6675.

Pursuant to the provisions of 40 CFR 63.6640(e), 40 CFR 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, do not apply to these emissions units.

- (l) **40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters:** This subpart applies to industrial, commercial, and institutional boilers and process heaters located at major sources of hazardous air pollutants. This facility has boilers and process heaters of the type regulated by this subpart. However, it is a minor source of HAPs. Therefore, this rule does not apply.
- (m) **40 CFR 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers Area Sources:** This subpart applies to industrial, commercial and institutional boilers located at area sources of HAPs. A boiler is defined as an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of boiler. The natural gas-fired startup heater is no an affected unit under this subpart. The auxiliary boilers meet the definition of boiler; however, natural gas-fired boilers are exempt from this subpart, pursuant to 40 CFR 63.11195(e).
- (n) **40 CFR 63, Subpart VVVVVV – National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources:** This subpart applies to all chemical manufacturing process units (CMPUs) located at area sources of HAPs that have a listed HAP present. The proposed processes located at this facility do not meet the definition of a subject CMPU. None of the units will use feed stocks that contain quinolone, manganese, trivalent chromium or a listed HAP in concentrations in excess of the listed thresholds. The units will not generate hydrazine or a listed HAP as a byproduct or product in present in any CMPU at a level above the listed thresholds. Therefore, this subpart does not apply.
- (o) **40 CFR 63, Subpart BBBB BBBB – National Emission Standards for Hazardous Air Pollutants for Area Sources: Chemical Preparations Industry:** This subpart applies to chemical preparations facilities located at an area source of HAPs that has at least one chemical preparations operation in target HAP service. Target HAP service includes process operations where raw materials, intermediates, or products contain one or more target HAP. Target HAPs contain chromium (VI), lead, or nickel in amounts greater than or equal to 0.1 percent by weight or manganese or chromium (III) compounds in amounts greater than 1 percent by weight. None of the chemical process operations located at this source contain a target HAP in excess of the listed thresholds. Therefore, this subpart does not apply.

# **CAM**

## **(a) 40 CFR 64 (Compliance Assurance Monitoring (CAM))**

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 described in 40 CFR 64.1, to comply with that emission limitation or standard.

IDEM, OAQ will only evaluate emission units with an installed control device to simplify the analysis. Units without a control device are never subject to CAM.

<b>CAM Applicability Table - NO<sub>x</sub></b>							
<b>Emission Unit</b>	<b>Control Device Used (Y/N)</b>	<b>Emission Limitation (Y/N)</b>	<b>Uncontrolled PTE (TPY)</b>	<b>Controlled PTE (TPY)</b>	<b>Part 70 Major Source Threshold</b>	<b>CAM Applicable (Y/N)</b>	<b>Large Unit (Y/N)</b>
Reformer Furnace	Y - SCR for NO <sub>x</sub>	Y	582.93	45.50	100	N	N
Nitric Acid Plant	Y – SCR for NO <sub>x</sub>	Y	473.74	23.69	100	N	N

The reformer furnace and nitric acid unit would be subject to CAM; however, the applicant has installed continuous emissions monitoring systems for NO<sub>x</sub>. Therefore, CAM does not apply.

<b>CAM Applicability Table – PM / PM10 / PM2.5</b>							
<b>Emission Unit</b>	<b>Control Device Used (Y/N)</b>	<b>Emission Limitation (Y/N)</b>	<b>Uncontrolled PTE (TPY)</b>	<b>Controlled PTE (TPY)</b>	<b>Part 70 Major Source Threshold</b>	<b>CAM Applicable (Y/N)</b>	<b>Large Unit (Y/N)</b>
Granulator	Wet Scrubber	Y	PM – 472.09 PM <sub>10</sub> – 472.09 PM <sub>2.5</sub> – 472.09	PM – 47.21 PM <sub>10</sub> – 47.21 PM <sub>2.5</sub> – 47.21	100	Y	N
Urea Warehouse	Baghouse	Y	PM – 11.24 PM <sub>10</sub> – 11.24 PM <sub>2.5</sub> – 11.24	PM – 0.73 PM <sub>10</sub> – 0.73 PM <sub>2.5</sub> – 0.73	100	N	N
Cooling Tower 10 Cell	Drift Eliminator	Y	PM – 3.24 PM <sub>10</sub> – 2.06 PM <sub>2.5</sub> – 0.01	PM – 3.24 PM <sub>10</sub> – 2.06 PM <sub>2.5</sub> – 0.01	100	N	N

CAM Applicability Table – PM / PM10 / PM2.5							
Emission Unit	Control Device Used (Y/N)	Emission Limitation (Y/N)	Uncontrolled PTE (TPY)	Controlled PTE (TPY)	Part 70 Major Source Threshold	CAM Applicable (Y/N)	Large Unit (Y/N)
Cooling Tower 6 Cell	Drift Eliminator	Y	PM – 1.95 PM <sub>10</sub> – 1.24 PM <sub>2.5</sub> – < 0.01	PM – 1.95 PM <sub>10</sub> – 1.24 PM <sub>2.5</sub> – < 0.01	100	N	N
Truck Loading	Fabric Filter	Y	PM – 11.24 PM <sub>10</sub> – 11.24 PM <sub>2.5</sub> – 11.24	PM – 0.53 PM <sub>10</sub> – 0.53 PM <sub>2.5</sub> – 0.53	100	N	N
Rail Loading	Fabric Filter	Y	PM – 11.24 PM <sub>10</sub> – 11.24 PM <sub>2.5</sub> – 11.24	PM – 0.92 PM <sub>10</sub> – 0.92 PM <sub>2.5</sub> – 0.92	100	N	N
Urea Junction	Fabric Filter	Y	PM – 11.24 PM <sub>10</sub> – 11.24 PM <sub>2.5</sub> – 11.24	PM – 0.92 PM <sub>10</sub> – 0.92 PM <sub>2.5</sub> – 0.92	100	N	N

Based on this evaluation, the requirements of 40 CFR 64, CAM are applicable to the urea granulator (EU-008) for PM, PM10 and PM2.5 upon issuance of the Title V Renewal. A CAM plan must be submitted as part of the Renewal application.

<b>State Rule Applicability - Entire Source</b>
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- (a) **326 IAC 1-5 (Episode Alert Levels):** This rule applies to all persons responsible for the operation of a source that has the potential to emit one hundred (100) tons per year or more of any pollutant. This source has the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO and NO<sub>x</sub> in excess of 100 tons per year. Therefore, this rule applies. The source shall submit an emergency reduction plan within 180 days after commencing operation.
- (b) **326 IAC 1-7 (Stack Height Provisions):** This rule applies to all sources having exhaust stacks through which twenty-five (25) tons per year or more of particulate matter or sulfur dioxide are emitted. The Urea Granulation Unit, identified as EU-008, has potential PM emissions in excess of 25 tons per year. Therefore, this rule applies.
- (c) **326 IAC 2-2 (Prevention of Significant Deterioration (PSD)):** This new stationary source is one of the 28 listed source categories and has the potential to emit of at least one regulated pollutant greater than 100 tons per year. Therefore, this is a major source pursuant to 326 IAC 2-2.
- (d) **326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements):** Pursuant to 326 IAC 2-2-3, construction of a new PSD major stationary source shall require a best available control (BACT) review for each regulated NSR pollutant for which the source has the potential to emit in significant amounts, as defined in 326 IAC 2-2-1(w). Major stationary source means a stationary source emitting or having the potential to emit 100 tons per year (TPY) or more of any criteria pollutant for sources specifically listed in the PSD regulations. Midwest Fertilizer Corporation is classified as a chemical process plant which is a specifically listed source in the PSD regulations. Midwest Fertilizer

Corporation has the potential to emit of greenhouse gases in excess of 100,000 tons per year and therefore the GHGs are subject to regulation under PSD. Midwest Fertilizer Corporation has the unrestricted potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and NO<sub>x</sub> in excess of 100 tons per year. The potential to emit PM (after controls) and VOC are in excess of the PSD significant levels of 25 tons per year and 40 tons per year, respectively. Therefore, a BACT review is required for PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, CO, NO<sub>x</sub> and greenhouse gas (GHG) emissions. See Appendix C to this Technical Support Document for the PSD Air Quality Analysis.

- (e) **326 IAC 2-2-5 (Air Quality Impact Requirements):** 326 IAC 2-2-5(e)(1) requires the air quality impact analysis to be conducted in accordance with the following provisions:

- (1) Any estimates of ambient air concentrations used in the demonstration process 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 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 the public comment procedures set forth in 326 IAC 2-1.1-6.

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

- (f) **326 IAC 2-2-6 (Increment Consumption Requirements):** 326 IAC 2-2-6(a) requires that any demonstration under 326 IAC 2-2-5 shall demonstrate that increased emissions caused by the proposed stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentrations of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, CO, NO<sub>x</sub> and Greenhouse Gases, indicated in 326 IAC 2-2-6(b)(1). PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, CO, NO<sub>x</sub> and Greenhouse Gases are emitted and subject to PSD in this proposed permit, T129-33576-00059.
- (g) **326 IAC 2-2-8 (Source Obligation):** Pursuant to 326 IAC 2-2-8(1), approval to construct, shall become invalid if construction is not commenced within eighteen (18) months after receipt of approval, if construction is discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time. 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.
- (h) **326 IAC 2-2-9 (Innovative Control Technology):** 326 IAC 2-2-9 allows any owner or operator of a proposed major stationary source or major modification may request the commissioner in writing to approve a system of innovative control technologies as part of the PSD application for T129-33576-00059.
- (i) **326 IAC 2-2-10 (Source Information):** The applicant has submitted all information necessary to perform or make the determination required by this rule.
- (j) **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 326 IAC 2-2-8.



- (k) **326 IAC 2-6 (Emission Reporting):** This source, not located in Lake, Porter, or LaPorte County, is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of VOC and PM10 is less than 250 tons per year; and the potential to emit of CO, NOx, and SO2 is less than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(2), triennial reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 by July 1, 2018 and every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.
- (l) **326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants):** This rule applies to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997. To construct a major source means to fabricate, erect or install at any greenfield site a stationary source or group of stationary sources which is located within a contiguous area and under common control and which emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of a combination of HAP. It also includes the fabrication, erection, or installation of a new process or production unit which emits or has the potential to emit 10 tons per year of a HAP or 25 tons per year of a combination of HAP by itself. The uncontrolled potential to emit hexane is greater than 10 tons per year, and the uncontrolled potential to emit total HAP is greater than 25 TPY. However, the applicant has accepted a hexane limitation on the reformer furnace (EU-001), the natural gas startup heater (EU-002), and the auxiliary boilers (EU-012A/B/C) to remain an area source of HAPs. The proposed limit is shown below:

HAP Minor Limit [326 IAC 2-4.1]

- (a) Combined hexane emissions from the reformer furnace (EU-001), the natural gas startup heater (EU-002), and the auxiliary boilers (EU-012A/B/C) shall not exceed 9.83 tons per twelve consecutive month period with compliance determined at the end of each month.
- (b) Hexane emissions shall be calculated with the following equation:

Hexane Emissions (ton/month) = Hexane Emissions from Reformer Furnace EU-001 Natural Gas + Hexane Emissions from Reformer Furnace EU-001 Process Gas + Hexane Emissions Startup Heater EU-002 + Hexane Emissions from Auxiliary Boiler EU-012A + Hexane Emissions from Auxiliary Boiler EU-012B + Hexane Emissions from Auxiliary Boiler EU-012C

Where:

Hexane Emissions Reformer Furnace EU-001 Natural Gas (ton/month) =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

Hexane Emissions Reformer Furnace EU-001 Process Gas (ton/month) =  
Process Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

Hexane Emissions Startup Heater EU-002 =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012A =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012B =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

Hexane Emissions from Auxiliary Boiler EU-012C =  
Natural Gas Usage (MMCF/Current Month) x Emission Factor (1.8 lb/MMCF, or  
as determined by testing) x 1 ton/2,000 lb

- (c) Natural gas and process gas usage shall be determined by flow monitoring of gases sent to the combustion unit, process operational data, mass balance or other engineering methods.

Compliance with the above limit shall ensure source-wide hexane emissions are less than ten (10) tons per twelve consecutive month period and source-wide total HAP emissions are less than twenty-five (25) tons per twelve consecutive month period and shall render the requirements of 326 IAC 2-4.1 (MACT) not applicable.

- (m) **326 IAC 5-1 (Opacity Regulations):** This rule applies to opacity, not including condensed water vapor, emitted by or from a facility or source. This facility has sources of opacity. Therefore, this rule applies. Pursuant to 326 IAC 5-1-2(1):
- (1) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period.
  - (2) 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.
- (n) **326 IAC 6-4 (Fugitive Dust Emissions):** This source applies to all sources of fugitive dust emissions. This source has fugitive dust emissions: therefore, this rule applies to the source.
- (o) **326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations):** This rule does not apply to this source for the following reasons:
- (1) Pursuant to 326 IAC 6-5-1(a), this rule applies to any source of fugitive particulate matter emissions located in nonattainment areas for particulate matter as designated by the Indiana Air Pollution Control Board, which has potential fugitive particulate matter emissions of twenty-five (25) tons per year or more. Posey County, Indiana is in attainment for all criteria pollutants and this source has a potential to emit fugitive PM emissions of less than 25 tons per year. Therefore, this rule does not apply to this source.
  - (2) Pursuant to 326 IAC 6-5-1(b), this rule applies to any 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. Since this source has a potential to emit fugitive PM emissions of less than 25 tons per year, the fugitive PM emissions do not require a permit. Therefore, this rule does not apply to this source.

- (p) **326 IAC 8-6 (Organic Solvent Emission Limitations):** This rule applies to sources with potential VOC emissions of 100 tons per year or greater, that were constructed prior to January 1, 1980, and are not regulated by other Article 8 rules. This rule does not apply to newly constructed sources. Therefore, it does not apply to this source.
- (q) **326 IAC 8-9 (Volatile Liquid Storage Vessels):** This rule applies to VOC storage tanks located in Clark, Floyd, Lake or Porter Counties. This source is located in Posey County; therefore, this rule does not apply to this source.
- (r) **326 IAC 8-17 (Industrial Solvent Cleaning Operations):** This rule applies to sources located in Lake or Porter Counties. This source is located in Posey County; therefore, this rule does not apply to this source.
- (s) **326 IAC 9 (Carbon Monoxide Emission Rules):** This rule establishes carbon monoxide emission limitations for petroleum refineries, ferrous metal smelters, refuse incineration and refuse burning equipment. Midwest Fertilizer Corporation is not a source regulated by 326 IAC 9; therefore, it does not apply to this source.
- (t) **326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories):** This rule applies to portland cement kilns, Boilers #7 to #12 at Bethlehem Steel Corporation, Boilers #4 to #8 at LTV Steel Company, and any other blast furnace gas-fired boiler with a heat input greater than 250 MMBtu/hr that is not subject to 326 IAC 10-4 or 326 IAC 24-3. The combustion turbines at this source do not meet the applicability criteria of this rule. Therefore, 326 IAC 10-3 does not apply.

<b>State Rule Applicability – Individual Facilities</b>
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**Reformer Furnace (EU-001)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:
  - (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the operation of the reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
  - (2) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;

- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall not exceed 1.9, 5.385 and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
  - (4) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
  - (5) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range;
  - (6) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average;
  - (7) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
  - (8) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
  - (9) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet stream flows;
  - (10) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
  - (11) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.
- (c) **326 IAC 3-5 (Continuous Monitoring of Emissions)**  
This rule applies to fossil fuel-fired steam generating units with a heat input capacity of 100 MMBtu/hr or more. The reformer furnace has a heat input capacity of greater than 100 MMBtu/hr; however, the reformer furnace is a process heater. Therefore, 326 IAC 3-5 does not apply to the reformer furnace. However, the applicant intends to install a NO<sub>x</sub> CEMS to facilitate compliance monitoring.
- (d) **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**  
This rule establishes particulate matter (PM) emission limitations for sources of indirect heating located anywhere in the state. The reformer furnace is a source of indirect heating and will be constructed in Posey County, Indiana. The reformer would normally be subject to 326 IAC 6-2-4 because it will be constructed after September 21, 1983. Pursuant to 326 IAC 6-2-1(g), the reformer is not subject to 326 IAC 6-2 because it is subject to an emission limitation pursuant to 326 IAC 2-2.

(e) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**

This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The reformer furnace (EU-001) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the reformer furnace.

**CO<sub>2</sub> Purification Process (EU-003)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the CO<sub>2</sub> purification process (EU-003) shall be as follows:

- (1) CO, VOC and CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;
- (2) CO emissions from the CO<sub>2</sub> purification process (EU-003) not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (3) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (4) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (5) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

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

326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The CO<sub>2</sub> purification process does not have the potential to emit particulate matter. Therefore, this rule does not apply to the CO<sub>2</sub> purification process.

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

This rule applies to new facilities constructed after January 1, 1980, that have potential VOC emissions of twenty-five (25) tons per year, are located anywhere in the state, and not otherwise regulated by another 326 IAC 8 rule, or 326 IAC 20-48, 326 IAC 20-56. The CO<sub>2</sub> purification process has potential VOC emissions of greater than 25 tons per year. Therefore, 326 IAC 8-1-6 applies to the CO<sub>2</sub> purification vent. This emission unit is also subject to BACT under 326 IAC 2-2 (Prevention of Significant Deterioration). PSD BACT for VOC will satisfy the 326 IAC 8-1-6 VOC BACT requirements.

**Startup Heater (EU-002)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the startup heater (EU-002) shall be as follows:

- (1) The startup heater (EU-002) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (3) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
- (5) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average;
- (6) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average;
- (7) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (8) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

- (c) **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**  
This rule establishes particulate matter (PM) emission limitations for sources of indirect heating located anywhere in the state. The startup heater (EU-002) is a source of indirect heating and will be constructed in Posey County, Indiana. The startup heater (EU-002) would normally be subject to 326 IAC 6-2-4 because it will be constructed after September 21, 1983. Pursuant to 326 IAC 6-2-1(g), the startup heater (EU-002) is not subject to 326 IAC 6-2; because, it is subject to an emission limitation pursuant to 326 IAC 2-2.
- (d) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The startup heater (EU-002) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the startup heater.

**Front End Flare (EU-017)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the front end flare (EU-017) shall be as follows:
- (1) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
  - (2) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.
  - (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events.
    - (A) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
    - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
  - (4) Flare emissions shall be controlled by use of the following practices:
    - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
    - (B) Flares shall be operated with a flame present at all times; and
    - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
  - (5) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
  - (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.
  - (7) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
  - (8) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.
  - (9) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
  - (10) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, during venting, based on a three-hour average.
  - (11) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
  - (12) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr, during venting, based on a three-hour average.
  - (13) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
  - (14) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, while venting, based on a three-hour average.
- (c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The front end flare (EU-017) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the front end flare.



**Back End Flare (EU-018)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the back end flare (EU-018) shall be as follows:
- (1) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
  - (2) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month;
  - (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
    - (A) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
    - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
    - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
  - (4) Flare emissions shall be controlled by use of the following practices:
    - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
    - (B) Flares shall be operated with a flame present at all times; and

- (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) PM emissions from the back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
- (7) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.
- (9) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.
- (11) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (12) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.
- (13) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (14) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.
- (c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The back end flare (EU-018) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the back end flare.

**Urea Synthesis Plant (EU-006)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The urea synthesis plant (EU-006) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea synthesis plant for these pollutants and BACT analyses are not required for these pollutants. The urea synthesis plant (EU-006) has the potential to emit 3.2 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM OAQ has determined that no further BACT analysis is required.

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

326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The urea synthesis plant does not have particulate matter emissions. Therefore, 326 IAC 6-3 does not apply to the urea synthesis plant.

**Urea Ammonium Nitrate (UAN) Plant (EU-007)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The urea ammonium nitrate plant (EU-007) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea ammonium nitrate plant for these pollutants and BACT analyses are not required for these pollutants.

The urea ammonium nitrate plant (EU-007) has the potential to emit 1,038 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from the urea ammonium nitrate plant as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

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

326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The urea ammonium nitrate plant does not have particulate matter emissions. Therefore, 326 IAC 6-3 does not apply to the urea ammonium nitrate plant.

### **Urea Granulation Unit (EU-008)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granulator (EU-008) shall be as follows:
- (1) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
  - (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall each not exceed 0.163 lb per ton granules, based on a three-hour average.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. Pursuant to 326 IAC 6-3(c)(1), the urea granulation unit is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

### **Urea Granule Storage Warehouse (EU-024)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granule storage warehouse (EU-024) shall be as follows:
- (1) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall each not exceed 0.17 lb/hr, based on a three-hour average.

- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. Pursuant to 326 IAC 6-3(c)(1), the urea granule storage warehouse is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

**Nitric Acid Plant (EU-009)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:
- (1) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton acid, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
  - (2) NO<sub>x</sub> and N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
  - (3) N<sub>2</sub>O emissions from each of the nitric acid plant (EU-009) shall not exceed 0.613 lb N<sub>2</sub>O per ton of nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The nitric acid plant does not have particulate matter emissions. Therefore, 326 IAC 6-3 does not apply to the nitric acid plant.

**Combustion Turbines (EU-013A and EU-013B)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the open-simple cycle combustion turbines (EU-013A/B) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design and good combustion practices at all times the units are in operation;
- (2) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (3) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0019 lb/MMBtu, based on a three-hour average;
- (4) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average;
- (5) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of dry low NO<sub>x</sub> combustors;
- (6) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average;
- (7) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average;
- (8) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average;
- (9) Thermal efficiency of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) emissions shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and

- (11) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.
- (c) **326 IAC 3-5 (Continuous Monitoring of Emissions)**  
This rule applies to any emissions unit required to perform continuous monitoring under 326 IAC 12 (NSPS Requirements). The applicant has accepted compliance options from NSPS Subpart KKKK that include the use of a continuous emissions monitoring system for NO<sub>x</sub>. Therefore, this rule applies to the open-simple cycle combustion turbines.
- (d) **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**  
This rule establishes particulate matter (PM) emission limitations for sources of indirect heating located anywhere in the state. The fossil fuel-fired combustion turbines are not sources of indirect heating, therefore, 326 IAC 6-2 does not apply.
- (e) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The combustion turbines each have a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the combustion turbines.
- (f) **326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)**  
This rule applies to portland cement kilns, Boilers #7 to #12 at Bethlehem Steel Corporation, Boilers #4 to #8 at LTV Steel Company, and any other blast furnace gas-fired boiler with a heat input greater than 250 MMBtu/hr that is not subject to 326 IAC 10-4 or 326 IAC 24-3. The combustion turbines at this source do not meet the applicability criteria of this rule. Therefore, 326 IAC 10-3 does not apply.
- (g) **326 IAC 24-1 (Clean Air Interstate Rule Nitrogen Oxides Annual Trading Program)**  
This rule applies to any stationary fossil fuel fired boiler or stationary fossil fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the startup of the unit's combustion turbine, a generator with a nameplate capacity of more than twenty-five (25) megawatt electrical producing electricity for sale. The natural gas-fired open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, each with a maximum heat input capacity of 283 MMBtu/hr, do not sell electricity to the grid. Therefore, 326 IAC 24-1 does not apply to the combustion turbines.
- (h) **326 IAC 24-2 (Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program)**  
This rule applies to any stationary fossil fuel fired boiler or stationary fossil fuel fired combustion turbine serving at any time, since the later of November 15, 1990 or the startup of the unit's combustion turbine, a generator with a nameplate capacity of more than twenty-five (25) megawatt electrical producing electricity for sale. The natural gas-fired open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, each with a maximum heat input capacity of 283 MMBtu/hr, do not sell electricity to the grid. Therefore, 326 IAC 24-2 does not apply to the combustion turbines.
- (i) **326 IAC 24-3 (Clean Air Interstate Rule NO<sub>x</sub> Ozone Season Trading Program)**  
This rule applies to any stationary fossil fuel fired boiler or stationary fossil fuel fired combustion turbine serving at any time, since the later of November 15, 1990 or the startup of the unit's combustion turbine, a generator with a nameplate capacity of more than twenty-five (25) megawatt electrical producing electricity for sale.

This rule also applies to any large affected unit. Pursuant to 326 IAC 24-3-2 (Definitions), large affected units include cogeneration units commencing operation on or after January 1, 1999, a unit with a maximum design heat input greater than 250

MMBtu/hr and qualifying as an unaffected unit under the acid rain program. It also applies to units that do not qualify as an unaffected unit under the acid rain program and serve a generator with a nameplate capacity greater than 25 MW, on or after January 1, 1999.

This rule does not apply to units subject to 326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories). The turbines are not subject to 326 IAC 10-3.

The natural gas-fired open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, each with a maximum heat input capacity of 283 MMBtu/hr, qualify as an unaffected unit under the acid rain program. A unit is defined as a fossil fuel-fired combustion device under 40 CFR 72.2. An affected unit is defined in 40 CFR 72.2 as a unit that is subject to any Acid Rain emissions reduction requirement of Acid Rain emissions limitation under 40 CFR 72.6 or 40 CFR 74. Pursuant to 40 CFR 72.6(b)(8), non-utility units are not affected units. The turbines are not opt-in units under 40 CFR 74. Therefore, the requirements of 326 IAC 24-3 apply.

### **Auxiliary Boilers (EU-012A, EU-012B and EU-012C)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies to the auxiliary boilers.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be as follows:

- (1) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC, and GHG emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (3) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (5) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;
- (6) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;



- (7) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average;
  - (8) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average;
  - (9) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
  - (10) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
  - (11) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
  - (12) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.
- (c) **326 IAC 3-5 (Continuous Monitoring of Emissions)**  
This rule applies to fossil fuel-fired steam generators of greater than 100 MMBtu/hr heat input capacity. 326 IAC 3-5 applies to the boilers (EU-012A, EU-012B and EU-012C), because they are fossil fuel-fired steam generating units over 100 MMBtu/hr. The applicant is not required to continuously monitor opacity; because, all three units will combust a gaseous fuel. The applicant is not required to continuously monitor SO<sub>2</sub>, because SO<sub>2</sub> control equipment has not been installed. The applicant is required to continuously monitor NO<sub>x</sub> emissions, because the source has installed a NO<sub>x</sub> control system, Flue Gas Recirculation (FGR).
- (d) **326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)**  
This rule establishes particulate matter (PM) emission limitations for sources of indirect heating located anywhere in the state. The auxiliary boilers are sources of indirect heating and will be constructed in Posey County, Indiana. The auxiliary boilers would normally be subject to 326 IAC 6-2-4; because, they will be constructed after September 21, 1983. Pursuant to 326 IAC 6-2-1(g), the auxiliary boilers are not subject to 326 IAC 6-2; because, they are subject to an emission limitation pursuant to 326 IAC 2-2.
- (e) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The auxiliary boilers each have a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the auxiliary boilers.
- (f) **326 IAC 8-1-6 BACT (General Reduction Requirements)**  
This rule applies to new facilities as of January 1, 1980, with potential emissions of twenty-five (25) tons per year or more of VOC, are located anywhere in the state, and are not otherwise regulated by 326 IAC 20-48 or 326 IAC 20-56. Each boiler has potential emissions of VOC of less than 25 TPY; therefore, 326 IAC 8-1-6 does not apply.

- (g) **326 IAC 9 (Carbon Monoxide Emission Rules)**  
This rule limits carbon monoxide emissions from petroleum refining operations, ferrous metal smelters, and refuse incineration and refuse burning equipment. The boilers are located at a fertilizer production facility and will combust natural gas. Therefore, this rule does not apply to the boilers.
- (h) **326 IAC 24 (Trading Programs: Nitrogen Oxides (NO<sub>x</sub>) and Sulfur Dioxide (SO<sub>2</sub>))**  
This rule applies to electric utility steam generating units and large affected units, defined as boilers and combustion turbines with a heat input capacity of 250 MMBtu/hr or more. Each boiler has a heat input capacity of less than 250 MMBtu/hr and the generators will not sell electricity to the grid. Therefore, 326 IAC 24 does not apply to the boilers.

**Fugitive Emissions from Equipment Leaks (F-1)**

- (a) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for fugitive emissions (F-1) shall be as follows:
- (1) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

**Truck Loading Operation (EU-020)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the truck loadout operation (EU-020) shall be as follows:
- (1) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. Pursuant to 326 IAC 6-3(c)(1), the truck loading operation is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

### **Rail Loading Operation (EU-021A)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for rail loading operation (EU-021A) shall be as follows:
- (1) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. Pursuant to 326 IAC 6-3(c)(1), the rail loading operation is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

### **Urea Junction Operation (EU-021B)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.

- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for urea junction operation (EU-021B) shall be as follows:
- (1) The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
  - (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. Pursuant to 326 IAC 6-3(c)(1), the urea junction operation is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

**Ammonia Storage Flare (EU-016)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan is required for the ammonia storage flare.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the ammonia storage flare (EU-016) shall be as follows:
- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
  - (2) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
  - (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
    - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
    - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
  - (4) Flare emissions shall be controlled by use of the following practices:
    - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
    - (B) Flares shall be operated with a flame present at all times; and
    - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
  - (5) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
  - (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
  - (7) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
  - (8) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.
  - (9) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
  - (10) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
  - (11) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operations, based on a three-hour average.
- (c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The ammonia storage flare (EU-016) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the ammonia storage flare.

**Distillate Oil-Fired Emergency Generator (EU-014)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency generator (EU-014) shall be as follows:
- (1) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
  - (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices;
  - (3) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
  - (4) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;
  - (5) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average;
  - (6) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average; and
  - (7) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr, based on a three-hour average.
- (c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The diesel-fired emergency generator (EU-014) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the emergency generator.
- (d) **326 IAC 10-5 (Nitrogen Oxide Reduction Program for Internal Combustion Engines)**  
This rule applies to the owner or operator of any large NO<sub>x</sub> SIP Call engine. A large NO<sub>x</sub> SIP Call engine is defined in the rule as the inventory of stationary internal combustion engines identified and designated as large in the NO<sub>x</sub> SIP Call engine inventory as emitting more than one ton of NO<sub>x</sub> per average ozone season day in 1995. The NO<sub>x</sub> SIP Call inventory means the inventory of internal combustion engines compiled by U.S. EPA as part of the NO<sub>x</sub> SIP Call rule, including the technical amendments announced in the March 2, 2000, Federal Register notice (65 FR 11222), and the adjustment of the 2007

budget NO<sub>x</sub> control efficiency to 82% for large gas-fired engines announced in the April 21, 2004, Federal Register notice (69 FR 21604) for the Phase II NO<sub>x</sub> SIP Call rule. The emergency generator is not listed in the inventory. Therefore, this rule does not apply.

#### **Distillate Oil-Fired Emergency Fire Water Pump (EU-015)**

(a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**

Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies to the fire water pump.

(b) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency fire water pump (EU-015) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

(c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**

This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The diesel-fired emergency fire water pump (EU-015) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the fire water pump.

- (d) **326 IAC 10-5 (Nitrogen Oxide Reduction Program for Internal Combustion Engines)**  
This rule applies to the owner or operator of any large NO<sub>x</sub> SIP Call engine. A large NO<sub>x</sub> SIP Call engine is defined in the rule as the inventory of stationary internal combustion engines identified and designated as large in the NO<sub>x</sub> SIP Call engine inventory as emitting more than one ton of NO<sub>x</sub> per average ozone season day in 1995. The NO<sub>x</sub> SIP Call inventory means the inventory of internal combustion engines compiled by U.S. EPA as part of the NO<sub>x</sub> SIP Call rule, including the technical amendments announced in the March 2, 2000, Federal Register notice (65 FR 11222), and the adjustment of the 2007 budget NO<sub>x</sub> control efficiency to 82% for large gas-fired engines announced in the April 21, 2004, Federal Register notice (69 FR 21604) for the Phase II NO<sub>x</sub> SIP Call rule. The emergency fire water pump is not listed in the inventory. Therefore, this rule does not apply.

**Distillate Oil-Fired Raw Water Pump (EU-063)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies to the raw water pump.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for emergency raw water pump (EU-063) shall be as follows:
- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
  - (2) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
  - (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
  - (4) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
  - (5) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
  - (6) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
  - (7) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.



- (c) **326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)**  
This rule applies to all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. The diesel-fired emergency raw water pump (EU-063) has a potential to emit sulfur dioxide of less than 25 tons per year and 10 pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to the raw water pump.
- (d) **326 IAC 10-5 (Nitrogen Oxide Reduction Program for Internal Combustion Engines)**  
This rule applies to the owner or operator of any large NO<sub>x</sub> SIP Call engine. A large NO<sub>x</sub> SIP Call engine is defined in the rule as the inventory of stationary internal combustion engines identified and designated as large in the NO<sub>x</sub> SIP Call engine inventory as emitting more than one ton of NO<sub>x</sub> per average ozone season day in 1995. The NO<sub>x</sub> SIP Call inventory means the inventory of internal combustion engines compiled by U.S. EPA as part of the NO<sub>x</sub> SIP Call rule, including the technical amendments announced in the March 2, 2000, Federal Register notice (65 FR 11222), and the adjustment of the 2007 budget NO<sub>x</sub> control efficiency to 82% for large gas-fired engines announced in the April 21, 2004, Federal Register notice (69 FR 21604) for the Phase II NO<sub>x</sub> SIP Call rule. The raw water pump is not listed in the inventory. Therefore, this rule does not apply.

**Ten Cell Evaporative Cooling Tower (EU-010)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies to the ten cell evaporative cooling tower.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for ten cell cooling tower (EU-010) shall be as follows:
- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
  - (2) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The ten cell cooling tower has potential PM emissions; however, it is not a manufacturing process. In addition, pursuant to 326 IAC 6-3(c)(1), the ten cell cooling tower is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

### **Six Cell Evaporative Cooling Tower (EU-011)**

- (a) **326 IAC 1-6-3 (Preventive Maintenance Plans)**  
Many types of facilities require maintenance in order to prevent excess emissions. In addition to preventive maintenance performed on the control devices, preventive maintenance should be performed on the emission unit being controlled. An improperly operated emission unit can result in an increase in uncontrolled emissions which increases pollutant loading to the control device. This may result in excess emissions. Pursuant to 326 IAC 2-7-4(c)(8) and 326 IAC 2-7-5(12), a preventive maintenance plan shall be prepared and maintained by all Title V sources for emission units and control devices where proper maintenance is required to minimize excess emissions. Therefore, this rule applies to the six cell evaporative cooling tower.
- (b) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the six cell cooling tower (EU-011) shall be as follows:
- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
  - (2) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.
- (c) **326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)**  
326 IAC 6-3 establishes emission limitations for particulate emissions from manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transmission of materials occurs that emits, or has the potential to emit, particulate in the production of the product. Transference, conveyance, or repair of a product are considered manufacturing processes. The six cell cooling tower has potential PM emissions; however, it is not a manufacturing process. In addition, pursuant to 326 IAC 6-3(c)(1), the six cell cooling tower is not subject to 326 IAC 6-3; because, it is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

### **Distillate Oil Storage Tank (EU-066)**

- (a) **326 IAC 2-2 (Prevention of Significant Deterioration)**  
The applicant provided information with the application indicating this emission source will not have PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gas (GHG) emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for these pollutants and BACT analyses are not required for these pollutants.
- The applicant provided information with the application indicating VOC emissions will be less than 0.01 tons per year. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.
- (b) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**  
This rule applies to all petroleum liquid storage vessels constructed after January 1, 1980 with a storage capacity greater than 39,000 gallons containing a volatile organic liquid whose true vapor pressure is greater than 10.5 kPa. The distillate oil storage tank has a storage capacity of less than 39,000 gallons. Therefore, 326 IAC 8-4-3 does not apply to the distillate oil storage tank.

### **Nitric Acid Storage Tank (EU-054)**

(a) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid storage tank for these pollutants and BACT analyses are not required for these pollutants.

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

(b) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**

This rule applies to all petroleum liquid storage vessels constructed after January 1, 1980 with a storage capacity greater than 39,000 gallons containing a volatile organic liquid whose true vapor pressure is greater than 10.5 kPa. An organic compound is any member of a large class of compounds in vapor, liquid, or solid phase containing carbon. Nitric acid (HNO<sub>3</sub>) does not contain carbon and is not an organic compound. Therefore, 326 IAC 8-4-3 does not apply to the nitric acid storage tank.

### **Urea Ammonium Nitrate Storage Tanks (EU-034, EU-035 and EU-036)**

(a) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea ammonium nitrate (UAN) storage tanks for these pollutants and BACT analyses are not required for these pollutants.

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from these units as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

(b) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**

This rule applies to all petroleum liquid storage vessels constructed after January 1, 1980 with a storage capacity greater than 39,000 gallons containing a volatile organic liquid whose true vapor pressure is greater than 10.5 kPa. Urea ammonium nitrate (UAN) is a solution of urea, (CO(NH<sub>2</sub>)<sub>2</sub>), ammonium nitrate (NH<sub>4</sub>NO<sub>3</sub>) and water. Urea Ammonium Nitrate Storage Tanks (EU-034, EU-035, and EU-036) each have a storage capacity greater than 39,000 gallons. However, UAN is an organic liquid but its true vapor pressure is less than 3.5 kPa. Therefore, this rule does not apply to the UAN storage tanks.

### **Diesel Exhaust Fluid Storage Tank (EU-037)**

(c) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the diesel exhaust fluid (DEF) storage tank for these pollutants and BACT analyses are not required for these pollutants.

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

(d) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**

This rule applies to all petroleum liquid storage vessels constructed after January 1, 1980 with a storage capacity greater than 39,000 gallons containing a volatile organic liquid whose true vapor pressure is greater than 10.5 kPa. Diesel exhaust fluid (DEF) is mixture of urea ( $\text{CO}(\text{NH}_2)_2$ ) and water. The diesel exhaust fluid storage tank (EU-037) has a storage capacity greater than 39,000 gallons. However, DEF is an organic liquid but its true vapor pressure is less than 3.5 kPa. Therefore, this rule does not apply to the DEF storage tank.

**OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) Storage Tank (EU-043)**

(a) **326 IAC 2-2 (Prevention of Significant Deterioration)**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to this unit for these pollutants and BACT analyses are not required for these pollutants.

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

(b) **326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)**

This rule applies to all petroleum liquid storage vessels constructed after January 1, 1980 with a storage capacity greater than 39,000 gallons containing a volatile organic liquid whose true vapor pressure is greater than 10.5 kPa. Storage tank (EU-043) has a storage capacity greater than 39,000 gallons. However, the OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) is an organic liquid with a true vapor pressure of less than 3.5 kPa. Therefore, 326 IAC 8-4-3 does not apply to this storage tank.

**Ammonia Storage Tanks (EU-032 and EU-033)**

(a) **326 IAC 2-2 (Prevention of Significant Deterioration)**

These storage tanks do not normally vent to the atmosphere. They are not subject to 326 IAC 2-2 PSD for any pollutants. Each tank is equipped with a pressure relief valve that can open during emergencies. The applicant has provided a flare to control these emissions to minimize odor complaints.

**Fugitive Dust – Paved Roads**

(a) **326 IAC 2-2 (Prevention of Significant Deterioration)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for paved roads and parking areas shall be as follows:

PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (1) Paving all plant haul roads;
- (2) Daily sweeping with wet suppression; and
- (3) Prompt cleanup of any spilled materials.

<b>Compliance Determination and Monitoring Requirements</b>
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Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

**The Compliance Determination Requirements applicable to this new source construction are as follows:**

Compliance Determination Requirements		
Emission Unit	Parameter	Frequency
Reformer Furnace (EU-001)	Use of SCR	At all times in operation, except startup and shutdown
	Hexane Record Keeping	Monthly
	CO <sub>2</sub> Emissions Record Keeping	Monthly
Nitric Acid Plant (EU-009)	Use of SCR	At all times in operation, except startup and shutdown
Startup Heater (EU-002)	Hexane Record Keeping	Monthly

Compliance Determination Requirements		
Emission Unit	Parameter	Frequency
Combustion Turbines (EU-013A/B)	CO <sub>2</sub> Emissions Record Keeping	Monthly
Front End Flare (EU-017)	NO <sub>x</sub> , CO, VOC, CO <sub>2</sub> Record Keeping	Monthly
Back End Flare (EU-018)	NO <sub>x</sub> , CO, VOC, CO <sub>2</sub> Record Keeping	Monthly
Ammonia Storage Flare (EU-016)	NO <sub>x</sub> , CO <sub>2</sub> Record Keeping	Monthly
Auxiliary Boilers (EU-012A/B/C)	Low NO <sub>x</sub> Burners Flue Gas Recirculation (FGR)	At all times in operation
	Hexane Record Keeping	Monthly
Urea Granulator (EU-008)	Use Scrubber	At all times in operation
Urea Granule Storage Warehouse (EU-024)	Use Baghouse	At all times in operation
Fugitive Emissions from Equipment Leaks (F-1)	Use Leak Detection and Repair (LDAR) Program	As specified in 40 CFR 60, Subpart VVa
Truck Loading (EU-020)	Use Baghouse	At all times in operation
Rail Loading (EU-021A)	Use Baghouse	At all times in operation
Urea Junction Operation (EU-021B)	Use Baghouse	At all times in operation

Summary of Testing Requirement				
Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency
Reformer Furnace (EU-001)	SCR	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			CO <sub>2</sub>	Every 5 Years
			Thermal Efficiency	One Time
CO <sub>2</sub> Purification Process (EU-003)	None	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			VOC	One Time
			CO <sub>2</sub>	One Time
Nitric Acid Unit (EU-009)	SCR/DeN <sub>2</sub> O	Within 60 days of max. capacity but no later than 180 days after startup	N <sub>2</sub> O	Every 5 Years
Urea Granulator (EU-008)	Wet Scrubber	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Urea Granule Storage Warehouse (EU-024)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Auxiliary Boilers (EU-012A/B/C)	Low NO <sub>x</sub> Burners, FGR	Within 60 days of max. capacity but no later than 180 days after startup	CO	One Time
			CO <sub>2</sub>	One Time
			Thermal Efficiency	One Time
Truck Loading (EU-020)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Rail Loading (EU-021A)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years
Urea Junction (EU-021B)	Baghouse	Within 60 days of max. capacity but no later than 180 days after startup	PM, PM <sub>10</sub> , PM <sub>2.5</sub>	Every 5 Years

Summary of Testing Requirement				
Emission Unit	Control Device	Timeframe for Testing	Pollutant	Frequency
Combustion Turbines (EU-013A/B)	Low NOx Dry Combustors	Within 60 days after reaching max. capacity, but no later than eighteen (18) months after initial startup of the turbines	NO <sub>x</sub>	Every 5 Years
			CO	One Time
			Thermal Efficiency	One Time
			CO <sub>2</sub>	One Time
		No later than 180 days after startup	NO <sub>x</sub>	One Time
			CO	One Time
			Thermal Efficiency	One Time
			CO <sub>2</sub>	One Time

The Compliance Monitoring Requirements applicable to this new source construction are as follows:

Summary of Monitoring Requirements			
Emission Units	Parameter	Frequency	Response to Excursions or Exceedances
Reformer Furnace (EU-001)	NO <sub>x</sub>	Continuous	A Reasonable Response
Front End Flare (EU-017)	Presence of Flame	Continuous	A Reasonable Response
Back End Flare (EU-018)	Presence of Flame	Continuous	A Reasonable Response
Ammonia Storage Flare (EU-016)	Presence of Flame	Continuous	A Reasonable Response
Urea Granulation Unit (EU-008)	Pressure Drop	Once per Day	A Reasonable Response



Summary of Monitoring Requirements			
Emission Units	Parameter	Frequency	Response to Excursions or Exceedances
Urea Granule Storage Warehouse (EU-024)	Pressure Drop	Once per Day	A Reasonable Response
Nitric Acid Plant (EU-009)	NO <sub>x</sub>	Continuous	A Reasonable Response
Auxiliary Boilers (EU-012A/B/C)	NO <sub>x</sub>	Continuous	A Reasonable Response
Truck Loading (EU-020)	Pressure Drop	Once per Day	A Reasonable Response
Rail Loading Operation (EU-021A)	Pressure Drop	Once per Day	A Reasonable Response
Urea Junction (EU-021B)	Pressure Drop	Once per Day	A Reasonable Response
Ten Cell Cooling Tower (EU-010)	Total Dissolved Solids	Once per Month	A Reasonable Response
Six Cell Cooling Tower (EU-011)	Total Dissolved Solids	Once per Month	A Reasonable Response
Emergency Generator (EU-014)	Operating Hours	Once per Month	A Reasonable Response
Fire Pump (EU-015)	Operating Hours	Once per Month	A Reasonable Response
Raw Water Pump (EU-063)	Operating Hours	Once per Month	A Reasonable Response

These monitoring conditions are necessary because the control devices must perform properly to ensure compliance with 326 IAC 2-2.

#### Recommendation

The staff recommends to the Commissioner that the PSD/New Source Construction and Part 70 Operating Permit be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on August 26, 2013.

#### Conclusion

The construction and operation of this source shall be subject to the conditions of the attached PSD/New Source Construction and Part 70 Operating Permit No. T129-33576-00059

<b>IDEM Contact</b>
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- (a) Questions regarding this proposed permit can be directed to David Matousek 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) 232-8253 or toll free at 1-800-451-6027 extension (2-8253).
- (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](http://www.idem.in.gov).

## Appendix A to the Technical Support Document (TSD) Emissions Summary Sheet

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 17, 2013

Uncontrolled PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	582.93	487,152	7.70	7.35
Natural Gas Startup Heater	EU-002	0.75	3.02	3.02	0.24	2.18	14.79	72.97	47,401	0.75	0.71
Auxiliary Boiler 1	EU-012A	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
Auxiliary Boiler 2	EU-012B	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
Auxiliary Boiler 3	EU-012C	1.78	7.13	7.13	0.56	5.16	34.94	19.15	112,021	1.77	1.69
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	3.86E-03	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	472.09	472.09	472.09	0.00	0.32	0.00	0.00	0	0.32	0.00
Urea Granule Storage	EU-024	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	473.74	1,407,400	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	190.27	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	190.27	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	3.16	0.63	0.16	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	11.24	11.24	11.24	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	215.53	214,890	0.00	0.00
PTE of Entire Source		555.67	598.16	594.40	7.88	109.97	1,079	1,796.54	4,023,910	25.64	13.21
Title V Major Source Thresholds		NA	100	100	100	100	100	100	100,000	25	10

(Continued Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Emissions Summary Sheet**  
(Continued from Previous Sheet)

Controlled PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	45.50	487,152	7.70	7.35
Natural Gas Startup Heater	EU-002	0.75	3.02	3.02	0.24	2.18	14.79	72.97	47,401	0.75	0.71
Auxiliary Boiler 1	EU-012A	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
Auxiliary Boiler 2	EU-012B	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
Auxiliary Boiler 3	EU-012C	1.78	7.13	7.13	0.56	5.16	34.94	11.49	112,021	1.77	1.69
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	3.86E-03	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	47.21	47.21	47.21	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Granule Storage	EU-024	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	23.69	70,370	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	0.32	0.06	0.02	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	215.53	214,890	0.00	0.00
Controlled PTE of Entire Source		71.80	116.56	113.23	7.88	109.65	1,079	612.40	2,686,880	25.32	13.21

(Continued Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Emissions Summary Sheet**  
(Continued Previous Sheet)

Limited PTE of the Entire Source (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Reformer Furnace	EU-001	7.76	21.98	21.98	2.45	22.45	177.37	45.50	487,152	7.70	9.83
Natural Gas Startup Heater	EU-002	0.017	0.069	0.069	0.005	0.05	0.34	1.67	1,082	0.02	
Auxiliary Boiler 1	EU-012A	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
Auxiliary Boiler 2	EU-012B	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
Auxiliary Boiler 3	EU-012C	1.43	5.71	5.71	0.45	4.13	27.95	9.19	89,617	1.42	
CO <sub>2</sub> Purification Process	EU-003	0.00	0.00	0.00	0.00	26.95	5.65	0.00	1,232,475	8.98	0.00
Front End Flare	EU-017	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Back End Flare	EU-018	0.03	0.13	0.13	0.01	0.09	6.48	1.19	2,050	0.03	0.03
Ammonia Storage Flare	EU-016	0.01	0.05	0.05	0.004	0.04	2.43	0.45	769	0.01	0.01
Urea Synthesis Plant	EU-006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19	0.00	0.00
UAN Plant	EU-007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,038	0.00	0.00
Urea Granulation Unit	EU-008	47.21	47.21	47.21	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Granule Storage	EU-024	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0	0.00	0.00
Nitric Acid Plant	EU-009	0.00	0.00	0.00	0.00	0.00	0.00	23.69	70,370	0.00	0.00
Turbine EU-013A	EU-013A	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Turbine EU-013B	EU-013B	2.36	9.42	9.42	1.74	8.68	37.19	103.43	145,032	1.24	0.00
Emergency Generator	EU-014	0.30	0.30	0.30	0.01	0.62	5.18	8.85	1,048	0.01	0.00
Fire Water Pump	EU-015	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Raw Water Pump	EU-063	0.04	0.04	0.04	1.37E-03	0.04	0.72	0.78	146	3.41E-03	0.00
Six Cell Cooling Tower	EU-011	1.95	1.24	4.14E-03	0.00	0.00	0.00	0.00	0	0.00	0.00
Ten Cell Cooling Tower	EU-010	3.24	2.06	0.01	0.00	0.00	0.00	0.00	0	0.00	0.00
Fugitive Leaks	F-1	0.00	0.00	0.00	0.00	14.39	0.07	0.01	1,215	0.01	0.00
Fugitives - Paved Roads	---	0.32	0.06	0.02	0.00	0.00	0.00	0.00	0	0.00	0.00
Storage Tanks	---	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.13	0	0.00	0.00
Truck Loading Operation	EU-020	0.53	0.53	0.53	0.00	0.00	0.00	0.00	0	0.00	0.00
Rail Loading Operation	EU-021A	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Junction Operation	EU-021B	0.92	0.92	0.92	0.00	0.00	0.00	0.00	0	0.00	0.00
Urea Warehouse	EU-024	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0	0.00	0.00
SSM Emissions	---	0.00	0.00	0.00	0.00	9.91	679.55	215.53	214,890	0.00	0.00
Limited PTE of the Entire Source		73.77	113.10	109.77	7.31	104.41	1,043	534.20	2,573,349	23.53	9.90
PSD Major Source Threshold		100	100	100	100	100	100	100	100,000	NA	NA
PSD Significant Level		25	15	10	40	40	100	NA	75,000	NA	NA

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-001 - Natural Gas Reformer

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Combustion

Heat Input	950.64 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Operation at PTE	8,760 hours/yr	or	8,164.32	MMCF/yr	
Limited Operation	8,760 hours/yr	or	8,164.32	MMCF/yr	

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 3% O <sub>2</sub>	Emission Factor Source
PM	1.9 lb/MMCF	7.76	0.00%	7.76	7.76		BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	5.385 lb/MMCF	21.98	0.00%	21.98	21.98		BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	5.385 lb/MMCF	21.98	0.00%	21.98	21.98		BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	2.45	0.00%	2.45	2.45		AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	22.45	0.00%	22.45	22.45		BACT Limit, AP-42, Ch. 1.4
CO	43.45 lb/MMCF	177.37	0.00%	177.37	177.37		BACT Limit
NO <sub>x</sub>	142.80 lb/MMCF	582.93	92.19%	45.50	45.50	9.00	BACT Limit/Applicant Estimate
Benzene	2.10E-03 lb/MMCF	8.57E-03	0.00%	8.57E-03	8.57E-03		AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	4.90E-03	0.00%	4.90E-03	4.90E-03		AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	3.06E-01	0.00%	3.06E-01	3.06E-01		AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	7.35	0.00%	7.35	7.35		AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	1.39E-02	0.00%	1.39E-02	1.39E-02		AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	2.04E-03	0.00%	2.04E-03	2.04E-03		AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	4.49E-03	0.00%	4.49E-03	4.49E-03		AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	5.72E-03	0.00%	5.72E-03	5.72E-03		AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	1.55E-03	0.00%	1.55E-03	1.55E-03		AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	8.57E-03	0.00%	8.57E-03	8.57E-03		AP-42, Ch. 1.4, Table 1.4-3
Total HAP		7.70		7.70	7.70		
CO <sub>2</sub>	59.61 ton/MMCF	486,675	0.00%	486,675	486,675		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	9.18	0.00%	9.18	9.18		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.92	0.00%	0.92	0.92		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		487,152		487,152	487,152		
CO <sub>2</sub> e (2013 Federal GWPs)		487,178		487,178	487,178		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmv NO<sub>x</sub> @ 3%) x 20.9 x Fd x K / (20.9-3) , Fd = 8,710, K = 1.194E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb

**Appendix A to the Technical Support Document (TSD)  
Emission Calculations - EU-002 - Natural Gas-Fired Startup Heater**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

**Operating Parameters - Natural Gas Combustion**

Heat Input	92.50 MMBtu/hr			
Natural Gas Heat Content	1,020 MMBtu/MMCF			
Hours of Operation for PTE	8,760 hours/yr	or	794.41	MMCF/yr
Limited Hours of Operation	200 hours/yr	or	18.14	MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	0.75	0.00%	0.75	0.017	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	3.02	0.00%	3.02	0.069	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	3.02	0.00%	3.02	0.069	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.24	0.00%	0.24	0.005	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	2.18	0.00%	2.18	0.05	BACT Limit, AP-42, Ch. 1.4
CO	37.23 lb/MMCF	14.79	0.00%	14.79	0.34	BACT Limit
NO <sub>x</sub>	183.70 lb/MMCF	72.97	0.00%	72.97	1.67	BACT Limit
Benzene	2.10E-03 lb/MMCF	8.34E-04	0.00%	8.34E-04	1.90E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	4.77E-04	0.00%	4.77E-04	1.09E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	2.98E-02	0.00%	2.98E-02	6.80E-04	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.71	0.00%	0.71	0.02	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	1.35E-03	0.00%	1.35E-03	3.08E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	1.99E-04	0.00%	1.99E-04	4.54E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	4.37E-04	0.00%	4.37E-04	9.98E-06	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	5.56E-04	0.00%	5.56E-04	1.27E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	1.51E-04	0.00%	1.51E-04	3.45E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	8.34E-04	0.00%	8.34E-04	1.90E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.75		0.75	0.02	
CO <sub>2</sub>	59.61 ton/MMCF	47,355	0.00%	47,355	1,081	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.89	0.00%	0.89	0.02	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.09	0.00%	0.09	0.00	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		47,401		47,401	1,082	
CO <sub>2</sub> e (2013 Federal GWPs)		47,404		47,404	1,082	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-012A - Auxiliary Boiler 1

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]4
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)



## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-012B - Auxiliary Boiler 2

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-012C - Auxiliary Boiler 3

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Natural Gas Boiler

Heat Input	218.60 MMBtu/hr				
Natural Gas Heat Content	1,020 MMBtu/MMCF				
Hours of Operation PTE	8,760 hours/yr	or	1,877.39	MMCF/yr	
Limited Operation	7,008 hours/yr	or	1,501.91	MMCF/yr	

Natural Gas Fired Boiler - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1.78	0.00%	1.78	1.43	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	7.6 lb/MMCF	7.13	0.00%	7.13	5.71	BACT Limit
SO <sub>2</sub>	0.6 lb/MMCF	0.56	0.00%	0.56	0.45	AP-42, Ch. 1.4, Table 1.4-2
VOC	5.5 lb/MMCF	5.16	0.00%	5.16	4.13	BACT Limit, AP-42, Ch. 1.4
CO	37.22 lb/MMCF	34.94	0.00%	34.94	27.95	BACT Limit
NO <sub>x</sub>	20.4 lb/MMCF	19.15	40.00%	11.49	9.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	1.13E-03	0.00%	1.13E-03	9.01E-04	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	7.04E-02	0.00%	7.04E-02	5.63E-02	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	1.69	0.00%	1.69	1.35	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	3.19E-03	0.00%	3.19E-03	2.55E-03	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	4.69E-04	0.00%	4.69E-04	3.75E-04	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.03E-03	0.00%	1.03E-03	8.26E-04	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	1.31E-03	0.00%	1.31E-03	1.05E-03	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	3.57E-04	0.00%	3.57E-04	2.85E-04	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.97E-03	0.00%	1.97E-03	1.58E-03	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		1.77		1.77	1.42	
CO <sub>2</sub>	59.61 ton/MMCF	111,911	0.00%	111,911	89,529	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.11	0.00%	2.11	1.69	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.21	0.00%	0.21	0.17	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		112,021		112,021	89,617	
CO <sub>2</sub> e (2013 Federal GWPs)		112,027		112,027	89,621	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]4
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the TSD - Emission Calculations**  
**CO<sub>2</sub> Vent and Granulator Alternative Operating Scenarios (EU-003 and EU-008)**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 15, 2013

**Operational Scenario #1**

**CO<sub>2</sub> Vent Emissions - EU-003 - Operational Scenario #1**

Pollutant	Production Rate (ton ammonia/yr)	Emission Factor per Ton Ammonia		PTE (TPY)	% Vented to the Atmosphere	Vented PTE (TPY)	Sources
VOC	965,790	0.0558	lb/ton	26.95	100.00%	26.95	Engineering estimate. VOC and CO emissions are shown as uncontrolled. The catalyst is the process.
CO		0.0117	lb/ton	5.65	100.00%	5.65	
CO <sub>2</sub>		1.275	ton/ton	616	100.00%	616	
CO <sub>2</sub> e		2552.3	lb/ton	1,232,475	100.00%	1,232,475	
Methanol		0.018594	lb/ton	8.98	100.00%	8.98	
Total HAP		0.018594	lb/ton	8.98	100.00%	8.98	

**Granulator Emissions - EU-008 - Operational Scenario #1**

Pollutant	Production Rate (ton granules/day)	Emission Factor (lb/ton granules)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Sources
PM	0	1.630	lb/ton	0.00	90.00%	0.00	0.00	Engineering estimate, IDEM control efficiency
PM <sub>10</sub>		1.630	lb/ton	0.00	90.00%	0.00	0.00	
PM <sub>2.5</sub>		1.630	lb/ton	0.00	90.00%	0.00	0.00	
VOC		0.0011	lb/ton	0.00	0.00%	0.00	0.00	Engineering estimate
Methanol		0.0011	lb/ton	0.00	0.00%	0.00	0.00	
Total HAP		0.0011	lb/ton	0.00	0.00%	0.00	0.00	

**Total Emissions - Scenario #1**

Pollutant	PTE (TPY)	Controlled PTE (TPY)	Limited PTE (TPY)
PM	0.00	0.00	0.00
PM <sub>10</sub>	0.00	0.00	0.00
PM <sub>2.5</sub>	0.00	0.00	0.00
VOC	26.95	26.95	26.95
CO	5.65	5.65	5.65
CO <sub>2</sub> e	1,232,475	1,232,475	1,232,475
Methanol	8.98	8.98	8.98
Total HAP	8.98	8.98	8.98

(Continued on Next Sheet)

**Appendix A to the TSD - Emission Calculations**  
**CO<sub>2</sub> Vent and Granulator Alternative Operating Scenarios**  
(Continued from Previous Sheet)

**Operational Scenario #2**

**CO<sub>2</sub> Vent Emissions - EU-003 - Operational Scenario #2**

Pollutant	Production Rate (ton ammonia/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	% Vented to the Atmosphere	Vented PTE (TPY)	Sources
VOC	965,790	0.0558	lb/ton	26.95	35.00%	9.43	Engineering estimate. VOC and CO emissions are shown as uncontrolled. The catalyst is the process.
CO		0.0117	lb/ton	5.65	35.00%	1.98	
CO <sub>2</sub>		1.275	ton/ton	616	35.00%	215	
CO <sub>2</sub> e		2,552.3	lb/ton	1,232,475	35.00%	431,366	
Methanol		0.018594	lb/ton	8.98	35.00%	3.14	
Total HAP		0.018594	lb/ton	8.98	35.00%	3.14	

**Granulator Emissions - EU-008 - Operational Scenario #2**

Pollutant	Production Rate (ton granules/yr)	Emission Factor (lb/ton granules)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
PM	579,255	1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	Engineering estimate for controlled and limited emissions. IDEM assumed 95% control efficiency for particulate.
PM <sub>10</sub>		1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	
PM <sub>2.5</sub>		1.630	lb/ton	472.09	90.00%	47.21	47.21	0.163	
VOC		0.0011	lb/ton	0.32	0.00%	0.32	0.32		
Methanol		0.0011	lb/ton	0.32	0.00%	0.32	0.32		
Total HAP		0.0011	lb/ton	0.32	0.00%	0.32	0.32		

**Total Emissions - Scenario #2**

Pollutant	PTE (TPY)	Controlled PTE (TPY)	Limited PTE (TPY)
PM	472.09	47.21	47.21
PM <sub>10</sub>	472.09	47.21	47.21
PM <sub>2.5</sub>	472.09	47.21	47.21
VOC	27.26	9.75	9.75
CO	5.65	1.98	1.98
CO <sub>2</sub> e	1,232,475	431,366	431,366
Methanol	9.30	3.46	3.46
Total HAP	9.30	3.46	3.46

**Worst Case PTE - Both Scenario**

Pollutant	Worst Case Controlled PTE (TPY)	Worst Case Limited PTE (TPY)	Worst Case Scenario
PM	47.21	47.21	2
PM <sub>10</sub>	47.21	47.21	2
PM <sub>2.5</sub>	47.21	47.21	2
VOC	26.95	26.95	1
CO	5.65	5.65	1
CO <sub>2</sub> e	1,232,475	1,232,475	1
Methanol	8.98	8.98	1
Total HAP	8.98	8.98	1

**Appendix A to the TSD - Emission Calculations**  
**Urea Plant, UAN Plant, and Nitric Acid Plant Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 15, 2013

Urea Plant Scrubber Vent Emissions - EU-006									
Pollutant	Production Rate (ton urea melt/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
CO <sub>2</sub>	1,062,150	0.0060	lb/ton	3.19	0.00%	3.19	3.19	0.006	Engineering Estimate
CO <sub>2</sub> e		0.0060	lb/ton	3.19	0.00%	3.19	3.19	0.006	

UAN Plant Emissions - EU-007									
Pollutant	Production Rate (ton UAN/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
CO <sub>2</sub>	2,076,120	1.00	lb/ton	1,038	0.00%	1,038	1,038	1.00	Engineering Estimate
CO <sub>2</sub> e		1.00	lb/ton	1,038	0.00%	1,038	1,038	1.00	

Nitric Acid Unit Emissions - EU-009									
Pollutant	Production Rate (ton 100% Acid/yr)	Emission Factor (lb/ton ammonia)		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit (lb/ton)	Sources
NO <sub>x</sub>	740,220	1.280	lb/ton	473.74	95.00%	23.69	23.69	0.064	Engineering Estimate
N <sub>2</sub> O		12.26	lb/ton	4,538	95.00%	227	227	0.613	
CO <sub>2</sub> e		3,802.65	lb/ton	1,407,400	95.00%	70,370	70,370	190.13	

**Methodology:**

- 1) PTE (TPY) = Production Rate (ton/day) x Emission Factor (lb/ton) x 1 ton/2,000 lb x 365 day/yr
- 2) Controlled PTE (TPY) = Uncontrolled PTE (TPY) x ( 1 - control efficiency )
- 3) Limited PTE (TPY) is determined by enforceable permit conditions.

**Notes:**

- 1) All emission factors are from an engineering estimate. IDEM, OAQ will require emissions testing to verify each emission factor.

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-017 - Front End Flare Pilot Emissions

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	4.00 MMBtu/hr (Emissions for Pilot Only - See Sheet 30 for Venting Emissions)			
Natural Gas Heat Content	1,020 MMBtu/MMCF			
Hours of Operation for PTE	8,760 hours/yr	or	34.35	MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	34.35	MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.03	0.00%	0.03	0.03	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.09	0.00%	0.09	0.09	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	6.48	0.00%	6.48	6.48	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	1.19	0.00%	1.19	1.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	2.06E-05	0.00%	2.06E-05	2.06E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	1.29E-03	0.00%	1.29E-03	1.29E-03	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.03	0.00%	0.03	0.03	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	5.84E-05	0.00%	5.84E-05	5.84E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	8.59E-06	0.00%	8.59E-06	8.59E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.89E-05	0.00%	1.89E-05	1.89E-05	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	2.40E-05	0.00%	2.40E-05	2.40E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	6.53E-06	0.00%	6.53E-06	6.53E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.03		0.03	0.03	
CO <sub>2</sub>	116.89 lb/MMBtu	2,048	0.00%	2,048	2,048	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	3.86E-03	0.00%	3.86E-03	3.86E-03	40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		2,050		2,050	2,050	
CO <sub>2</sub> e (2013 Federal GWPs)		2,050		2,050	2,050	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

**Appendix A to the Technical Support Document (TSD)  
Emission Calculations - EU-018 - Back End Flare Pilot Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

**Operating Parameters - External Natural Gas Combustion**

Heat Input 4.00 MMBtu/hr (Emissions for Pilot Only - See Sheet 30 for Venting Emissions)  
 Natural Gas Heat Content 1,020 MMBtu/MMCF  
 Hours of Operation for PTE 8,760 hours/yr or 34.35 MMCF/yr  
 Limited Hours of Operation 8,760 hours/yr or 34.35 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.03	0.00%	0.03	0.03	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.13	0.00%	0.13	0.13	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.09	0.00%	0.09	0.09	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	6.48	0.00%	6.48	6.48	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	1.19	0.00%	1.19	1.19	BACT Limit
Benzene	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	2.06E-05	0.00%	2.06E-05	2.06E-05	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	1.29E-03	0.00%	1.29E-03	1.29E-03	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.03	0.00%	0.03	0.03	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	5.84E-05	0.00%	5.84E-05	5.84E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	8.59E-06	0.00%	8.59E-06	8.59E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	1.89E-05	0.00%	1.89E-05	1.89E-05	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	2.40E-05	0.00%	2.40E-05	2.40E-05	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	6.53E-06	0.00%	6.53E-06	6.53E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	3.61E-05	0.00%	3.61E-05	3.61E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.03		0.03	0.03	
CO <sub>2</sub>	116.89 lb/MMBtu	2,048	0.00%	2,048	2,048	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	3.86E-03	0.00%	3.86E-03	3.86E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		2,050		2,050	2,050	
CO <sub>2</sub> e (2013 Federal GWPs)		2,050		2,050	2,050	

**Methodology:**

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-016 - Ammonia Storage Flare Pilot Emissions

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	1.50 MMBtu/hr (Emissions for Pilot Only - See Sheet 30 for Venting Emissions)			
Natural Gas Heat Content	1,020 MMBtu/MMCF			
Hours of Operation for PTE	8,760 hours/yr	or	12.88	MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	12.88	MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)						
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.0019 lb/MMBtu	0.01	0.00%	0.01	0.01	BACT Limit, AP-42, Ch. 1.4
PM <sub>10</sub>	0.0075 lb/MMBtu	0.05	0.00%	0.05	0.05	BACT Limit, AP-42, Ch. 1.4
PM <sub>2.5</sub>	0.0075 lb/MMBtu	0.05	0.00%	0.05	0.05	BACT Limit, AP-42, Ch. 1.4
SO <sub>2</sub>	0.6 lb/MMCF	3.86E-03	0.00%	3.86E-03	3.86E-03	AP-42, Ch. 1.4, Table 1.4-2
VOC	0.0054 lb/MMBtu	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 1.4
CO	0.37 lb/MMBtu	2.43	0.00%	2.43	2.43	BACT Limit
NO <sub>x</sub>	0.068 lb/MMBtu	0.45	0.00%	0.45	0.45	BACT Limit
Benzene	2.10E-03 lb/MMCF	1.35E-05	0.00%	1.35E-05	1.35E-05	AP-42, Ch. 1.4, Table 1.4-3
Dichlorobenzene	1.20E-03 lb/MMCF	7.73E-06	0.00%	7.73E-06	7.73E-06	AP-42, Ch. 1.4, Table 1.4-3
Formaldehyde	7.50E-02 lb/MMCF	4.83E-04	0.00%	4.83E-04	4.83E-04	AP-42, Ch. 1.4, Table 1.4-3
Hexane	1.80 lb/MMCF	0.01	0.00%	0.01	0.01	AP-42, Ch. 1.4, Table 1.4-3
Toluene	3.40E-03 lb/MMCF	2.19E-05	0.00%	2.19E-05	2.19E-05	AP-42, Ch. 1.4, Table 1.4-3
Lead	5.00E-04 lb/MMCF	3.22E-06	0.00%	3.22E-06	3.22E-06	AP-42, Ch. 1.4, Table 1.4-3
Cadmium	1.10E-03 lb/MMCF	7.09E-06	0.00%	7.09E-06	7.09E-06	AP-42, Ch. 1.4, Table 1.4-3
Chromium	1.40E-03 lb/MMCF	9.02E-06	0.00%	9.02E-06	9.02E-06	AP-42, Ch. 1.4, Table 1.4-3
Manganese	3.80E-04 lb/MMCF	2.45E-06	0.00%	2.45E-06	2.45E-06	AP-42, Ch. 1.4, Table 1.4-3
Nickel	2.10E-03 lb/MMCF	1.35E-05	0.00%	1.35E-05	1.35E-05	AP-42, Ch. 1.4, Table 1.4-3
Total HAP		0.01		0.01	0.01	
CO <sub>2</sub>	116.89 lb/MMBtu	768	0.00%	768	768	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.01	0.00%	0.01	0.01	40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	1.45E-03	0.00%	1.45E-03	1.45E-03	40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		769		769	769	
CO <sub>2</sub> e (2013 Federal GWPs)		769		769	769	

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)



**Appendix A to the Technical Support Document (TSD)  
Granular Ammonium Nitrate Loadout and Storage Emissions**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

PM Emissions (TPY)											
Emission Unit Description	Emission Unit ID	Throughput (Ton/yr)	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (lb/hr)	Limited PTE (TPY)	Limit (lb/ton)	Data Source
Truck Loading	EU-020	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.12	0.53	0.00094	AP-42, Ch. 8.3, Table 8.3-2
Rail Loading	EU-021A	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.0016	AP-42, Ch. 8.3, Table 8.3-2
Urea Junction	EU-021B	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.0016	AP-42, Ch. 8.3, Table 8.3-2
Urea Warehouse	EU-024	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.17	0.73	0.0013	AP-42, Ch. 8.3, Table 8.3-2

PM <sub>10</sub> and PM <sub>2.5</sub> Emissions (TPY)											
Emission Unit Description	Emission Unit ID	Throughput (Ton/yr)	Emission Factor		PTE (TPY)	Control Efficiency (%)	Controlled PTE (TPY)	Limited PTE (lb/hr)	Limited PTE (TPY)	Limit (lb/ton)	Data Source
Truck Loading	EU-020	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.12	0.53	0.00094	AP-42, Ch. 8.3, Table 8.3-2
Rail Loading	EU-021A	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.00164	AP-42, Ch. 8.3, Table 8.3-2
Urea Junction	EU-021B	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.21	0.92	0.00164	AP-42, Ch. 8.3, Table 8.3-2
Urea Warehouse	EU-024	1,124,000	0.02	lb/ton	11.24	99.90%	0.01	0.17	0.73	0.00130	AP-42, Ch. 8.3, Table 8.3-2

**Methodology:**

- 1) PTE (TPY) = Throughput (ton urea/day) x 365 day/year x emission factor (lb/ton urea) x 1 ton /2,000 lb
- 2) Controlled PTE (TPY) = PTE (TPY) x ( 1 - control efficiency )
- 3) PTE (lb/ton) = Limited PTE (TPY) x 2,000 lb/ton / throughput (ton/year)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-013A - Natural Gas Combustion Turbine

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 1, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	283.00 MMBtu/hr		
Natural Gas Heat Content	1,020 MMBtu/MMCF		
Hours of Operation for PTE	8,760 hours/yr	or	2,430.47 MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	2,430.47 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 15% O <sub>2</sub>	Emission Factor Source
PM	1.90E-03 lb/MMBtu	2.36	0.00%	2.36	2.36		BACT Limit
PM <sub>10</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
PM <sub>2.5</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
SO <sub>2</sub> (S=15 PPM)	1.40E-03 lb/MMBtu	1.74	0.00%	1.74	1.74		AP-42, Ch. 3.1, April 2000, Table 3.1-2a
VOC	7.00E-03 lb/MMBtu	8.68	0.00%	8.68	8.68		BACT Limit
CO	0.03 lb/MMBtu	37.19	0.00%	37.19	37.19		BACT Limit
NO <sub>x</sub>	0.1535 lb/MMBtu	190.27	45.64%	103.43	103.43	22.65	BACT Limit
Benzene	1.20E-05 lb/MMBtu	1.49E-02	0.00%	1.49E-02	1.49E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Toluene	1.30E-04 lb/MMBtu	1.61E-01	0.00%	1.61E-01	1.61E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Xylene	6.40E-05 lb/MMBtu	7.93E-02	0.00%	7.93E-02	7.93E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Formaldehyde	7.10E-04 lb/MMBtu	8.80E-01	0.00%	8.80E-01	8.80E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
1,3-Butadiene	4.30E-07 lb/MMBtu	5.33E-04	0.00%	5.33E-04	5.33E-04		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acetaldehyde	4.00E-05 lb/MMBtu	4.96E-02	0.00%	4.96E-02	4.96E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acrolein	6.40E-06 lb/MMBtu	7.93E-03	0.00%	7.93E-03	7.93E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Ethylbenzene	3.20E-05 lb/MMBtu	3.97E-02	0.00%	3.97E-02	3.97E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Naphthalene	1.30E-06 lb/MMBtu	1.61E-03	0.00%	1.61E-03	1.61E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Polycyclic Aromatic Hydrocarbons	2.20E-06 lb/MMBtu	2.73E-03	0.00%	2.73E-03	2.73E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Total HAP		1.24		1.24	1.24		
CO <sub>2</sub>	116.89 lb/MMBtu	144,890	0.00%	144,890	144,890		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.73	0.00%	2.73	2.73		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.27	0.00%	2.73E-01	2.73E-01		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		145,032		145,032	145,032		
CO <sub>2</sub> e (2013 Federal GWPs)		145,040		145,040	145,040		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmvd NO<sub>x</sub> @ 15%) x 20.9 x Fd x K / (20.9-15), Fd = 8,710, K = 1.194 E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-013B - Natural Gas Combustion Turbine

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 1, 2013

### Operating Parameters - External Natural Gas Combustion

Heat Input	283.00 MMBtu/hr		
Natural Gas Heat Content	1,020 MMBtu/MMCF		
Hours of Operation for PTE	8,760 hours/yr	or	2,430.47 MMCF/yr
Limited Hours of Operation	8,760 hours/yr	or	2,430.47 MMCF/yr

Natural Gas Combustion - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Limit ppm <sub>vd</sub> at 15% O <sub>2</sub>	Emission Factor Source
PM	1.90E-03 lb/MMBtu	2.36	0.00%	2.36	2.36		BACT Limit
PM <sub>10</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
PM <sub>2.5</sub>	7.60E-03 lb/MMBtu	9.42	0.00%	9.42	9.42		BACT Limit
SO <sub>2</sub> (S=15 PPM)	1.40E-03 lb/MMBtu	1.74	0.00%	1.74	1.74		AP-42, Ch. 3.1, April 2000, Table 3.1-2a
VOC	7.00E-03 lb/MMBtu	8.68	0.00%	8.68	8.68		BACT Limit
CO	0.03 lb/MMBtu	37.19	0.00%	37.19	37.19		BACT Limit
NO <sub>x</sub>	0.1535 lb/MMBtu	190.27	45.64%	103.43	103.43	22.65	BACT Limit
Benzene	1.20E-05 lb/MMBtu	1.49E-02	0.00%	1.49E-02	1.49E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Toluene	1.30E-04 lb/MMBtu	1.61E-01	0.00%	1.61E-01	1.61E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Xylene	6.40E-05 lb/MMBtu	7.93E-02	0.00%	7.93E-02	7.93E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Formaldehyde	7.10E-04 lb/MMBtu	8.80E-01	0.00%	8.80E-01	8.80E-01		AP-42, Ch. 3.1, April 2000, Table 3.1-3
1,3-Butadiene	4.30E-07 lb/MMBtu	5.33E-04	0.00%	5.33E-04	5.33E-04		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acetaldehyde	4.00E-05 lb/MMBtu	4.96E-02	0.00%	4.96E-02	4.96E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Acrolein	6.40E-06 lb/MMBtu	7.93E-03	0.00%	7.93E-03	7.93E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Ethylbenzene	3.20E-05 lb/MMBtu	3.97E-02	0.00%	3.97E-02	3.97E-02		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Naphthalene	1.30E-06 lb/MMBtu	1.61E-03	0.00%	1.61E-03	1.61E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Polycyclic Aromatic Hydrocarbons	2.20E-06 lb/MMBtu	2.73E-03	0.00%	2.73E-03	2.73E-03		AP-42, Ch. 3.1, April 2000, Table 3.1-3
Total HAP		1.24		1.24	1.24		
CO <sub>2</sub>	116.89 lb/MMBtu	144,890	0.00%	144,890	144,890		BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	1.00E-03 kg/MMBtu	2.73	0.00%	2.73	2.73		40 CFR 98, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.27	0.00%	2.73E-01	2.73E-01		40 CFR 98, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		145,032		145,032	145,032		
CO <sub>2</sub> e (2013 Federal GWPs)		145,040		145,040	145,040		

### Methodology:

- 1) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 4) PTE (TPY CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 5) Fuel Usage (MMCF/yr) = Heat Input (MMBtu/hr) x Operating Hours (hr/yr) ÷ Fuel Heat Content (MMBtu/MMCF)
- 6) Emission Factor (lb/MMBtu) = Emission Factor (lb/MMCF) ÷ Fuel Heat Content (MMBtu/MMCF)
- 7) NO<sub>x</sub> (lb/MMBtu) = (ppmvd NO<sub>x</sub> @ 15%) x 20.9 x Fd x K / (20.9-15), Fd = 8,710, K = 1.194 E-07
- 8) Limited NO<sub>x</sub> PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x ton/2,000 lb

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-014 - Emergency Generator

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Diesel Fired Generator

Engine Output	3,600 HP				
Brake Specific Fuel Consumption	6,597 Btu/Hp.Hr				
Heat Input	23.75 MMBtu/hr				
Diesel Fuel Heat Content	140 MMBtu/kgal				
Hours of Operation PTE	500 hours/yr	or	84.82	kgallon/yr	
Hours of Operation Limited PTE	500 hours/yr	or	84.82	kgallon/yr	

Diesel Fired Generator - Emission Calculations (TPY)							
Pollutant	Emission Factor		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
PM <sub>10</sub>	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
PM <sub>2.5</sub>	0.15	g/hp-hr	0.30	0.00%	0.30	0.30	BACT Limit, AP-42, Ch. 3.4
SO <sub>2</sub>	0.0015	lb/MMBtu	8.91E-03	0.00%	8.91E-03	8.91E-03	Design Specification
VOC	0.31	g/hp-hr	0.62	0.00%	0.62	0.62	BACT Limit, AP-42, Ch. 3.4
CO	2.61	g/hp-hr	5.18	0.00%	5.18	5.18	BACT Limit
NO <sub>x</sub>	4.46	g/hp-hr	8.85	0.00%	8.85	8.85	BACT Limit
Hazardous Air Pollutants							
Benzene	7.76E-04	lb/MMBtu	4.61E-03	0.00%	4.61E-03	4.61E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Toluene	2.81E-04	lb/MMBtu	1.67E-03	0.00%	1.67E-03	1.67E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Xylene	1.93E-04	lb/MMBtu	1.15E-03	0.00%	1.15E-03	1.15E-03	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Formaldehyde	7.89E-05	lb/MMBtu	4.68E-04	0.00%	4.68E-04	4.68E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Acetaldehyde	2.52E-05	lb/MMBtu	1.50E-04	0.00%	1.50E-04	1.50E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Acrolein	7.88E-06	lb/MMBtu	4.68E-05	0.00%	4.68E-05	4.68E-05	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Naphthalene	1.30E-04	lb/MMBtu	7.72E-04	0.00%	7.72E-04	7.72E-04	AP-42, Ch. 3.4, Table 3.4-3 and 3.4-4
Total HAP			8.86E-03		8.86E-03	8.86E-03	
Greenhouse Gas Emissions							
CO <sub>2</sub>	526.39	g/hp-hr	1,044	0.00%	1,044	1,044	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	3.00E-03	kg/MMBtu	0.04	0.00%	0.04	0.04	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	6.00E-04	kg/MMBtu	7.85E-03	0.00%	7.85E-03	7.85E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)			1,048		1,048	1,048	
CO <sub>2</sub> e (2013 Federal GWPs)			1,048		1,048	1,048	

### **Methodology:**

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-015 - Fire Water Pump

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Diesel Fired Pump

Engine Output	500 HP			
Brake Specific Fuel Consumption	7,280 Btu/Hp.Hr			
Heat Input	3.64 MMBtu/hr			
Diesel Fuel Heat Content	140 MMBtu/kgal			
Hours of Operation PTE	500 hours/yr	or	13.00	kgallon/yr
Hours of Operation Limited PTE	500 hours/yr	or	13.00	kgallon/yr

Diesel Fired Pump - Emission Calculations (TPY)							
Pollutant	Emission Factor		PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
PM <sub>10</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
PM <sub>2.5</sub>	0.15	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
SO <sub>2</sub>	0.0015	lb/MMBtu	1.37E-03	0.00%	1.37E-03	1.37E-03	Design Specification
VOC	0.141	g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, Ch. 3.3
CO	2.60	g/hp-hr	0.72	0.00%	0.72	0.72	BACT Limit
NO <sub>x</sub>	2.83	g/hp-hr	0.78	0.00%	0.78	0.78	BACT Limit
Hazardous Air Pollutants							
Benzene	9.33E-04	lb/MMBtu	8.49E-04	0.00%	8.49E-04	8.49E-04	AP-42, Ch. 3.3, Table 3.3-2
Toluene	4.09E-04	lb/MMBtu	3.72E-04	0.00%	3.72E-04	3.72E-04	AP-42, Ch. 3.3, Table 3.3-2
Xylene	2.85E-04	lb/MMBtu	2.59E-04	0.00%	2.59E-04	2.59E-04	AP-42, Ch. 3.3, Table 3.3-2
Formaldehyde	1.18E-03	lb/MMBtu	1.07E-03	0.00%	1.07E-03	1.07E-03	AP-42, Ch. 3.3, Table 3.3-2
Acetaldehyde	7.67E-04	lb/MMBtu	6.98E-04	0.00%	6.98E-04	6.98E-04	AP-42, Ch. 3.3, Table 3.3-2
Acrolein	9.25E-05	lb/MMBtu	8.42E-05	0.00%	8.42E-05	8.42E-05	AP-42, Ch. 3.3, Table 3.3-2
Naphthalene	8.48E-05	lb/MMBtu	7.72E-05	0.00%	7.72E-05	7.72E-05	AP-42, Ch. 3.3, Table 3.3-2
Total HAP			3.41E-03		3.41E-03	3.41E-03	
Greenhouse Gas Emissions							
CO <sub>2</sub>	527.40	g/hp-hr	145	0.00%	145	145	BACT Limit, 40 CFR 98, Subpart C
CH <sub>4</sub>	3.00E-03	kg/MMBtu	0.01	0.00%	0.01	0.01	40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	6.00E-04	kg/MMBtu	1.20E-03	0.00%	1.20E-03	1.20E-03	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)			146		146	146	
CO <sub>2</sub> e (2013 Federal GWPs)			146		146	146	

### Methodology:

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

## Appendix A to the Technical Support Document (TSD) Emission Calculations - EU-063 - Raw Water Pump

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

### Operating Parameters - Diesel Fired Pump

Engine Output	500 HP			
Brake Specific Fuel Consumption	7,280 Btu/Hp.Hr			
Heat Input	3.64 MMBtu/hr			
Diesel Fuel Heat Content	140 MMBtu/kgal			
Hours of Operation PTE	500 hours/yr	or	13.00	kgallon/yr
Hours of Operation Limited PTE	500 hours/yr	or	13.00	kgallon/yr

Diesel Fired Pump - Emission Calculations (TPY)							
Pollutant	Emission Factor	PTE (TPY)	Control Efficiency	Controlled PTE (TPY)	Limited PTE (TPY)	Emission Factor Source	
PM	0.15 g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3	
PM <sub>10</sub>	0.15 g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3	
PM <sub>2.5</sub>	0.15 g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3	
SO <sub>2</sub>	0.0015 lb/MMBtu	1.37E-03	0.00%	1.37E-03	1.37E-03	Design Specification	
VOC	0.141 g/hp-hr	0.04	0.00%	0.04	0.04	BACT Limit, AP-42, CH. 3.3	
CO	2.60 g/hp-hr	0.72	0.00%	0.72	0.72	BACT Limit	
NO <sub>x</sub>	2.83 g/hp-hr	0.78	0.00%	0.78	0.78	BACT Limit	
Benzene	9.33E-04 lb/MMBtu	8.49E-04	0.00%	8.49E-04	8.49E-04	AP-42, Ch. 3.3, Table 3.3-2	
Toluene	4.09E-04 lb/MMBtu	3.72E-04	0.00%	3.72E-04	3.72E-04	AP-42, Ch. 3.3, Table 3.3-2	
Xylene	2.85E-04 lb/MMBtu	2.59E-04	0.00%	2.59E-04	2.59E-04	AP-42, Ch. 3.3, Table 3.3-2	
Formaldehyde	1.18E-03 lb/MMBtu	1.07E-03	0.00%	1.07E-03	1.07E-03	AP-42, Ch. 3.3, Table 3.3-2	
Acetaldehyde	7.67E-04 lb/MMBtu	6.98E-04	0.00%	6.98E-04	6.98E-04	AP-42, Ch. 3.3, Table 3.3-2	
Acrolein	9.25E-05 lb/MMBtu	8.42E-05	0.00%	8.42E-05	8.42E-05	AP-42, Ch. 3.3, Table 3.3-2	
Naphthalene	8.48E-05 lb/MMBtu	7.72E-05	0.00%	7.72E-05	7.72E-05	AP-42, Ch. 3.3, Table 3.3-2	
Total HAP		3.41E-03		3.41E-03	3.41E-03		
CO <sub>2</sub>	527.40 g/hp-hr	145	0.00%	145	145	BACT Limit, 40 CFR 98, Subpart C	
CH <sub>4</sub>	3.00E-03 kg/MMBtu	6.02E-03	0.00%	6.02E-03	6.02E-03	40 CFR 98, Table C-2	
N <sub>2</sub> O	6.00E-04 kg/MMBtu	1.20E-03	0.00%	1.20E-03	1.20E-03	40 CFR 98, Table C-2	
CO <sub>2</sub> e (2009 Federal GWPs)		146		146	146		
CO <sub>2</sub> e (2013 Federal GWPs)		146		146	146		

### Methodology:

- 1) PTE (TPY) = Emission Factor (g/hp-hr) x Output (HP) x Operating Hours (hours/yr) x 1 lb/453.59 g x 1 ton/2,000 lb
- 2) PTE (TPY) = Emission Factor (lb/MMBtu) x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 3) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Heat Input (MMBtu/hr) x Operating Hours (hr/yr) x 1 ton/2,000 lb
- 4) PTE (TPY as CO<sub>2</sub>e (2009 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 21] + [TPY N<sub>2</sub>O x 310]
- 5) PTE (TPY as CO<sub>2</sub>e (2013 Federal GWPs)) = [TPY CO<sub>2</sub>] + [TPY CH<sub>4</sub> x 25] + [TPY N<sub>2</sub>O x 298]
- 6) Engine Heat Input (MMBtu/hr) = Output (HP) x Brake Specific Fuel Consumption (Btu/Hp-hr) x 1 MMBtu/1,000,000 Btu
- 7) Fuel Consumption (kgal/yr) = [Operating Hours (hr/yr) x Heat Input (MMBtu/hr)] ÷ Fuel Heat Content (MMBtu/kgal)

**Appendix A to the Technical Support Document (TSD)  
Emission Calculations - EU-010 and EU-011 - Cooling Towers**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

Emission Unit	Description	Circulation Rate (GPM)	Drift Factor (%)	Solids Content (mg/l)	Pollutant	Mass Fraction (%)	Annual Emissions (TPY)
EU-011	Six Cell Cooling Tower	88,762	0.0005%	2,000	PM	100%	1.95
					PM <sub>10</sub>	63.50%	1.24
					PM <sub>2.5</sub>	0.213%	4.14E-03
EU-010	Ten Cell Cooling Tower	147,937	0.0005%	2,000	PM	100%	3.24
					PM <sub>10</sub>	63.50%	2.06
					PM <sub>2.5</sub>	0.213%	6.91E-03

**Methodology:**

- 1) PM<sub>10</sub> and PM<sub>2.5</sub> mass fractions were estimated using, "Calculating Realistic PM<sub>10</sub> Emissions from Cooling Towers," by Reisman, J. and Frisbie, G.
- 2) PM emissions (lb/hr) = Q (GPM) x 60 min/hr x 8.34 lb/gallon x solids concentration (mg/l / 1E06) x Drift % / 100
- 3) PM Emissions (TPY) = PM Emissions (lb/hr) x 4.38 ton-hr/lb-yr
- 4) PM<sub>10/2.5</sub> = PM Emissions (TPY) x mass %

## Appendix A to the Technical Support Document (TSD)

### Potential Emissions from Component Leaks

Company Name: Midwest Fertilizer Corporation

Address: Intersection Old SR 69 and Mackey Ferry Road East  
Mt. Vernon, Indiana 47620

Permit Number: T 129-33576-00059

Reviewer: David Matousek

Date: October 2, 2013

Summary of Potential Fugitive Leaks (TPY)						
Pollutant	Reformer and Ammonia Units	aMDEA Area	UAN Plant Area 1	UAN Plant Area 2	UAN Product Storage Area	Total Emissions
CO	0.07	0.00	0.00	0.00	0.00	0.07
NO <sub>x</sub>	0.00	0.00	0.00	8.23E-03	0.00	0.01
VOC	0.00	3.64	8.84	0.00	1.91	14.39
Methanol	9.39E-03	0.00	0.00	0.00	0.00	0.01
CO <sub>2</sub>	39.68	0.00	3.91	0.49	0.00	44.08
CH <sub>4</sub>	7.20	0.00	0.00	0.00	0.00	7.20
N <sub>2</sub> O	0.00	0.00	0.00	3.29	0.00	3.29
CO <sub>2</sub> e (2009 GWPs)	190.93	0.00	3.91	1,021	0.00	1,215
CO <sub>2</sub> e (2013 GWPs)	219.74	0.00	3.91	981	0.00	1,205

#### 1) Reformer and Ammonia Units

Component	Type Service	Emission Factor (lb/hr/component t)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	170	9.80
	Light Liquid	0.00888	210	8.17
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealless	0.04387	8	1.54
	Light Liquid Single Seal	0.04387	0	0.00
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	292	1.10
	Light Liquid	0.00024	35	0.04
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	2	4.40
Relief Valves	Rupture Disk	0.22928	18	18.08
	Gas/Vapor	0.22928	2	2.01
Open Ended Lines	---	0.00375	111	1.82
Sampling Ports	---	0.03307	0	0.00
Total Fugitive Emissions				46.95

Fugitive Emissions Reformer and Ammonia Units		
Pollutant	Mass % Total	PTE (TPY)
CO	0.14%	0.07
NO <sub>x</sub>	0.00%	0.00
VOC	0.00%	0.00
Methanol	0.02%	9.39E-03
CO <sub>2</sub>	84.51%	39.68
CH <sub>4</sub>	15.34%	7.20
N <sub>2</sub> O	0.00%	0.00

#### Methodology:

- 1) See Sheet 23

(Continued Next Sheet)



**Appendix A to the Technical Support Document (TSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**2) aMDEA Area**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	0	0.00
	Light Liquid	0.00888	0	0.00
	Heavy Liquid	0.00051	152	0.34
Pumps	Light Liquid Sealless	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	0	0.00
	Heavy Liquid Single Seal	0.019	9	0.75
Flanges	Gas/Vapor	0.00086	0	0.00
	Light Liquid	0.00024	0	0.00
	Heavy Liquid	0.000001	750	3.29E-03
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	2	2.01
Open Ended Lines	---	0.00375	8	0.13
Sampling Ports	---	0.03307	28	4.06
<b>Total Fugitive Emissions</b>				<b>7.29</b>

aMDEA Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	50.00%	3.64
Methanol	0.00%	0.00
CO <sub>2</sub>	0.00%	0.00
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

- 1) Fugitive Emissions (TPY) = Emission Factor (lb/hr/component) x Number Components x 4.38 ton-hr/lb-year
- 2) Pollutant Emissions (TPY) = Total Fugitive Emission (ton/yr) x Mass % pollutant

**Notes:**

- 1) Emission Factors from Table 2-1, Protocol for Equipment Leak Emission Estimated, EPA 453/R-95-017, November 1995.

(Continued Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**3) UAN Plant Area 1**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	82	4.73
	Light Liquid	0.00888	196	7.62
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealless	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	6	1.15
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	132	0.50
	Light Liquid	0.00024	238	0.25
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	6	6.03
Open Ended Lines	---	0.00375	0	0.00
Sampling Ports	---	0.03307	2	0.29

**Total Fugitive Emissions      20.57**

UAN Plant Area 1 Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	43.00%	8.84
Methanol	0.00%	0.00
CO <sub>2</sub>	19.00%	3.91
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

1) See Sheet 23

(Continued Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**4) UAN Plant Area 2**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	82	4.73
	Light Liquid	0.00888	196	7.62
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealless	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	6	1.15
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	132	0.50
	Light Liquid	0.00024	238	0.25
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	6	6.03
Open Ended Lines	---	0.00375	0	0.00
Sampling Ports	---	0.03307	2	0.29
<b>Total Fugitive Emissions</b>				<b>20.57</b>

UAN Plant Area 2 Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.04%	8.23E-03
VOC	0.00%	0.00
Methanol	0.00%	0.00
CO <sub>2</sub>	2.39%	0.49
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	16.00%	3.29

**Methodology:**

- 1) See Sheet 23

(Continued Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Potential Emissions from Component Leaks**  
(Continued from Previous Sheet)

**5) UAN Product Storage**

Component	Type Service	Emission Factor (lb/hr/component)	Number of Components	Fugitive Emissions (TPY)
Valves	Gas/Vapor	0.01316	0	0.00
	Light Liquid	0.00888	110	4.28
	Heavy Liquid	0.00051	0	0.00
Pumps	Light Liquid Sealess	0.04387	0	0.00
	Light Liquid Single Seal	0.04387	2	0.38
	Heavy Liquid Single Seal	0.019	0	0.00
Flanges	Gas/Vapor	0.00086	0	0.00
	Light Liquid	0.00024	260	0.27
	Heavy Liquid	0.000001	0	0.00
Compressors	Gas/Vapor	0.50265	0	0.00
Relief Valves	Rupture Disk	0.22928	0	0.00
	Gas/Vapor	0.22928	0	0.00
Open Ended Lines	---	0.00375	22	0.36
Sampling Ports	---	0.03307	0	0.00
<b>Total Fugitive Emissions</b>				<b>5.30</b>

UAN Product Storage Potential Fugitive Emissions		
Pollutant	Mass % Total	PTE (TPY)
CO	0.00%	0.00
NO <sub>x</sub>	0.00%	0.00
VOC	36.00%	1.91
Methanol	0.00%	0.00
CO <sub>2</sub>	0.00%	0.00
CH <sub>4</sub>	0.00%	0.00
N <sub>2</sub> O	0.00%	0.00

**Methodology:**

- 1) See Sheet 23

**Appendix A to the Technical Support Document (TSD)  
Fugitive Particulate Emissions from Paved Roads and Parking Lots**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** September 26, 2013

Average Vehicle Weight Calculation							
Vehicle Type	Trucks/Day	Average Weight (tons)	Total Trips per Year	Miles per Trip	Vehicle Miles Traveled (VMT) (miles/year)	Traffic Component (%)	Component Weight (tons)
Bulk Truck	250	26.00	91,250	0.114	10,402.50	100.00%	26.00

Total VMT (miles/year)	10,402.50
------------------------	-----------

W - Average Vehicle Weight (ton)	26.00
----------------------------------	-------

**Site Specific Constants**

Value Name	Symbol	Value	Units	Source
Emission Factor	E	---	lb/VMT	Calculated
Particle Size Multiplier	k for PM	0.011	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Particle Size Multiplier	k for PM <sub>10</sub>	0.0022	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Particle Size Multiplier	k for PM <sub>2.5</sub>	0.00054	lb/VMT	AP-42, Ch 13.2.1, Table 13.2.1-1, 01/2011
Silt Loading	sL (Average)	2.35	grain/cubic meter	Provided by Applicant, Higher than AP-42, Ch. 13.2.1
Days >0.01" of rain	P	125	days	AP-42, Ch 13.2.1, Figure 13.2.1-2, 01/2011
Total Days in Period	N	365	days	Days in Year
Mean Vehicle Weight	W	26.00	ton	Calculated Above

(Continued on Next Sheet)

**Appendix A to the Technical Support Document (TSD)**  
**Fugitive Particulate Emissions from Paved Roads and Parking Lots**  
(Continued)

**Average Emission Factors**

AP-42, Chapter 13.2.1-5, 01/2011, Equation 2

$$E = [ k * (\text{Average sL})^{0.91} * (W)^{1.02} ] * [ 1 - P/(4 * N) ]$$

E for PM (lb/VMT) = 0.61 lb/VMT

E for PM<sub>10</sub> (lb/VMT) = 0.12 lb/VMT

E for PM<sub>2.5</sub> (lb/VMT) = 0.03 lb/VMT

**Uncontrolled Potential to Emit**

PM (TPY) = [Annual Average E for PM (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 3.16 TPY

PM<sub>10</sub> (TPY) = [Annual Average E for PM<sub>10</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.63 TPY

PM<sub>2.5</sub> (TPY) = [Annual Average E for PM<sub>2.5</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.16 TPY

**Controlled Potential to Emit**

Control Efficiency 90% based on BACT Limit

PM (TPY) = [Annual Average E for PM (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.32 TPY

PM<sub>10</sub> (TPY) = [Annual Average E for PM<sub>10</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.06 TPY

PM<sub>2.5</sub> (TPY) = [Annual Average E for PM<sub>2.5</sub> (lb/VMT) \* Total VMT/year \* 1 ton / 2,000 lb] 0.02 TPY

**Appendix A to the Technical Support Document (TSD)  
Emissions Summary Sheet - Insignificant Activities - Storage Tanks**

**Company Name:** Midwest Fertilizer Corporation  
**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
 Mt. Vernon, Indiana 47620  
**Permit Number:** T 129-33576-00059  
**Reviewer:** David Matousek  
**Date:** October 2, 2013

Uncontrolled PTE of Storage Tanks (TPY)											
Process / Emission Unit	Unit ID	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	GHGs (CO <sub>2</sub> e)	Total HAP	Worst Case HAP Hexane
Ammonia Storage Tank	EU-032	Pressurized Tanks - No Normal Emissions									
Ammonia Storage Tank	EU-033										
UAN Storage Tank	EU-034	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
UAN Storage Tank	EU-035	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
UAN Storage Tank	EU-036	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
DEF Storage Tank	EU-037	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
OASE/MDEA Storage Tank	EU-043	0.00	0.00	0.00	0.00	negl.	0.00	0.00	0.00	negl.	0.00
Nitric Acid Storage Tank	EU-054	0.00	0.00	0.00	0.00	negl.	0.00	0.13	0.00	negl.	0.00
Diesel Fuel Storage Tank	EU-066	0.00	0.00	0.00	0.00	2.00E-03	0.00	0.00	0.00	negl.	negl.
<b>Storage Tanks Total</b>		<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>2.00E-03</b>	<b>0.00</b>	<b>0.13</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>

## Appendix A to the Technical Support Document (TSD) Startup, Shutdown and Maintenance Emissions

**Company Name:** Midwest Fertilizer Corporation

**Address:** Intersection Old SR 69 and Mackey Ferry Road East  
Mt. Vernon, Indiana 47620

**Permit Number:** T 129-33576-00059

**Reviewer:** David Matousek

**Date:** October 17, 2013

### 1) Ammonia Storage Flare (EU-016)

Annual Hours of Venting 168 hours per year  
Maximum Ammonia Feed Rate 9,075 lb ammonia per hour  
Maximum Flare Heat Input 69.18 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub> - Thermal	0.068 lb/MMBtu	0.40		AP-42, Ch. 13.5, Table 13.5-1
NO <sub>x</sub> - Fuel	0.01325 lb NO <sub>x</sub> / lb Ammonia	10.10		Design Specification
Total NO <sub>x</sub> Emissions		10.50	125.00 lb/hr	
N <sub>2</sub> O	1.00E-04 kg CO <sub>2</sub> /MMBtu	1.28E-03	negligible	40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		0.40	negligible	
CO <sub>2</sub> e (2013 Federal GWPs)		0.38		

### 2) Front End Flare (EU-017)

Annual Hours of Venting 336 hours per year  
Maximum Flare Heat Input 8,757.20 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub>	0.068 lb/MMBtu	100.04	595.49 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
VOC	0.0054 lb/MMBtu	7.94	47.26 lb/hr	AP-42, Ch. 1.4, Table 1.4-2
CO	0.37 lb/MMBtu	544.35	3,240.16 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO <sub>2</sub>	53.02 kg/MMBtu	171,967	511.81 ton/hr	40 CFR 98, Subpart C, Table C-1
CH <sub>4</sub>	1.00E-03 kg/MMBtu	3.24		40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.32		40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		172,136		
CO <sub>2</sub> e (2013 Federal GWPs)		172,145		

### 3) Back End Flare (EU-018)

Annual Hours of Venting 336 hours per year  
Maximum Ammonia Feed Rate 36,000 lb ammonia per hour  
Maximum Flare Heat Input 2,175.07 MMBtu/hr

Pollutant	Emission Factor	PTE (TPY)	PTE	Data Source
NO <sub>x</sub> - Thermal	0.068 lb/MMBtu	24.85		AP-42, Ch. 13.5, Table 13.5-1
NO <sub>x</sub> - Fuel	0.01325 lb NO <sub>x</sub> / lb Ammonia	80.14		Design Specification
Total NO <sub>x</sub> Emissions		104.99	624.94 lb/hr	
VOC	0.0054 lb/MMBtu	1.97	11.73 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO	0.37 lb/MMBtu	135.20	804.76 lb/hr	AP-42, Ch. 13.5, Table 13.5-1
CO <sub>2</sub>	53.02 kg/MMBtu	42,712	127.12 ton/hr	40 CFR 98, Subpart C, Table C-1
CH <sub>4</sub>	1.00E-03 kg/MMBtu	0.81		40 CFR 98, Subpart C, Table C-2
N <sub>2</sub> O	1.00E-04 kg/MMBtu	0.08		40 CFR 98, Subpart C, Table C-2
CO <sub>2</sub> e (2009 Federal GWPs)		42,754		
CO <sub>2</sub> e (2013 Federal GWPs)		42,756		

SSM Summary (TPY)			
VOC	CO	NO <sub>x</sub>	GHG-2009
9.91	679.55	215.53	214,890

#### Methodology:

- 1) PTE (TPY) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu) x hr/yr x 1 ton/2,000 lb
- 2) PTE (TPY) = Throughput (lb/hr) x Emission Factor (lb/lb) x hr/yr x 1 ton/2,000 lb
- 3) PTE (lb/hr) = PTE (TPY) x 2,000 lb/ton x ( 1 / hr/yr)



**Indiana Department of Environmental Management  
Office of Air Quality**

**Appendix B to the Technical Support Document (TSD)  
BACT Analysis**

<b>Source Background and Description</b>
--

Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Road East Mt. Vernon, Indiana 47620
County:	Posey County
SIC Code:	2873 (Nitrogenous Fertilizers)
Permit Number:	T129-33576-00059
Permit Reviewer:	David Matousek

<b>Proposed Construction</b>
------------------------------

On August 26, 2013, Midwest Fertilizer Corporation submitted an air permit application to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The application proposed the construction of a nitrogen fertilizer manufacturing facility located in Mt. Vernon, Indiana. The proposed nitrogen fertilizer manufacturing facility is capable of producing anhydrous ammonia, nitric acid, liquid urea, diesel exhaust fluid (DEF), granulated urea, and urea ammonium nitrate (UAN) solutions. Final products will be shipped from the facility by truck and/or rail. The source will be categorized as a major source for Prevention of Significant Deterioration (PSD) and an area source of Hazardous Air Pollutants (HAPs). Construction will be subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)).

<b>Requirement for Best Available Control Technology (BACT)</b>
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326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) requires a Best Available Control Technology (BACT) review for construction of any new PSD major stationary source that will have major and significant amounts of air pollution for any criteria pollutant. Major means emitting or have the potential to emit 100 tons per year (TPY) or more of any criteria pollutant for sources specifically listed in the PSD regulations. Midwest Fertilizer Corporation is classified as a chemical process plant which is a specifically listed source in the PSD regulations. Significant refers to threshold levels listed in the PSD regulations and assigned to each criteria pollutant, certain non-criteria pollutants and pollutants subject to regulation like greenhouse gases (GHGs).

The construction of the proposed facility will have major emissions of PM (before control), PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and NO<sub>x</sub> and will have GHG emissions that are greater than 100,000 TPY as CO<sub>2e</sub> and subject to regulation under PSD. The proposed facility will have significant emissions of PM (after control) and VOC. The significant levels are 25 tons per year for PM and 40 tons per year for VOC. BACT analyses were performed for PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, NO<sub>x</sub>, VOC and GHGs.

<b>BACT Review – Subject Units</b>
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**Emission Units**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.
  - (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.
- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.
- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017, approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.
- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.
- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]
- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.
- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]
- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively. [40 CFR 60, Subpart KKKK]
- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]

- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1. [40 CFR 60, Subpart VVa]
- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.
- (l) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-021A.
- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

#### **Insignificant Activities**

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]
- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]
- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]
- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]
- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]
- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]
- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]
- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tank does not contain an organic liquid. [326 IAC 2-2]

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]
- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]

#### 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, Midwest Fertilizer Corporation will be required to demonstrate that the emissions will be reduced to the 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. Midwest Fertilizer Corporation has not submitted any innovative control technology for consideration. Only available and proven control technologies were 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 and any more stringent limits established from other RBLC Permits.

### **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 economic or environmental analysis. In no case can the selected BACT be less stringent than any New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or Reasonably Available Control Technologies (RACT) standard or emission limit.

### **Step 5: Select BACT**

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. The final BACT determination would be the technology with the most stringent corresponding limit that is economically feasible. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

## **BACT Analysis – Reformer Furnace (EU-001)**

### **Emission Unit Description**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (1) One (1) 950.64 MMBtu/hr reformer furnace, identified as emission unit EU-001, approved for construction in 2014, combusting a combination of process gas and natural gas, with NO<sub>x</sub> emissions controlled by low NO<sub>x</sub> burners and a Selective Catalytic Reduction (SCR) Unit, identified as SCR-1, NO<sub>x</sub> CEMS and exhausting to stack S-001.

### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) microns (PM<sub>10</sub>), and particulate matter with an aerodynamic diameter less than or equal to two and one half (2.5) microns (PM<sub>2.5</sub>) are generally controlled with an add-on control device designed to capture the emissions before they are exhausted to the atmosphere. The most common add-on control technologies are shown below:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses)

The choice of which technology is most appropriate for a specific application will depend on numerous factors, including: the size of particle, particle loading, desired collection efficiency, stack gas flow rate and the physical properties of the stack gas. Important stack gas properties include: temperature, moisture content, and the presence of reactive materials. For combustion units, it is not unusual for a source to use alternate control measures in place of the above listed control technologies. One or more alternative methods of control may be considered when they are more cost effective than add-on controls or when add-on control may not be feasible. IDEM, OAQ and the applicant have evaluated the following alternative control methods:

- (a) Fuel Specifications - Clean Burning Fuel; and
- (b) Good Combustion Practices.

#### **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<sub>10</sub> in the reformer furnace (EU-001) exhaust is very low (~0.005 gr/cf), a cyclone is not a technically feasible control option for the reformer furnace (EU-001).

(b) **Wet Scrubber**

Wet scrubbers use a flow or spray of liquid in a tower to contact particulate-laden exhaust gas streams 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 ppm<sub>v</sub>. (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. A wet scrubber is not a technically feasible control option for the reformer furnace (EU-001).

(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<sup>3</sup>. Since the pollutant concentration of the reformer furnace (EU-001) exhaust is already orders of magnitude lower, an ESP would not achieve any appreciable additional particulate control. An electrostatic precipitator is not a technically feasible control option for the reformer furnace (EU-001).

- (d) **Fabric Filter Dust Collectors (Baghouse)**  
A baghouse uses a fabric filter to capture particles as the gas stream flows through the fabric. A 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 control device for this source. A fabric filter dust collector is not a technically feasible control option for the reformer furnace (EU-001).
- (e) **Fuel Specifications – Clean Burning Fuel**  
Clean burning natural gas has a very low potential for generating PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions. Fuel specifications are technically feasible control option for the reformer furnace (EU-001).
- (e) **Good Combustion Practices / Combustion Controls**  
Good combustion practices as well as operation and maintenance of the reformer furnace to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the reformer furnace (EU-001):

- (a) Fuel Specifications – Clean Burning Fuel
- (b) Good Combustion Practices

The applicant intends to use natural gas as well as good combustion practices to minimize particulate emissions from the reformer. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Reformer Furnace (EU-001) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr natural gas	PM/PM <sub>10</sub> /PM <sub>2.5</sub> -0.0024 lb/MMBtu 11.9 TPY, rolling 12 month total	Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	PM-1.9 lb/MMCF PM <sub>10</sub> -5.385 lb/MMCF PM <sub>2.5</sub> -5.385 lb/MMCF based on 3-hr avg.	Use Natural Gas/Process Gas, Proper Design, Good Combustion

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Reformer Furnace (EU-001) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	Ohio Valley Resources	09/25/13	Primary Reformer	1,006.40 MMBtu/hr	1.9, 7.6 and 7.6 lb/MMCF, PM/PM <sub>10</sub> /PM <sub>2.5</sub> , respectively 3 hr avg.	Good Combustion Practices, natural gas/process gas
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas Vent	1,412 MMBtu/hr	PM <sub>10</sub> - 0.0075 lb/MMBtu, 3 hour avg.	Proper Design, Operation, and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Methane Reformer	337 MMBtu/hr	PM <sub>10</sub> - 0.0075 lb/MMBtu, 1 hr avg.; 2.52 lb/hr	Combust Gaseous Fuel Only
OK-0135	Pryor Plant Chemical Company	02/23/09	Primary Reformer	700 ton ammonia/day 225 MMBtu/hr	PM-1.68 lb/hr PM <sub>10</sub> -1.26 lb/hr	None

#### RBLC Review

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate any source is using add-on control technologies for PM/ PM<sub>10</sub>/PM<sub>2.5</sub> emissions from natural gas-fired reformers or furnaces. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate for PM will be 1.9 lb/MMCF from a natural gas-fired reformer. The Iowa Fertilizer Company has the lowest listed emission rates for PM, PM<sub>10</sub> and PM<sub>2.5</sub>.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) Fuel Specifications – Natural Gas / Process Gas Combustion
- (b) Good Combustion Practices, Proper Design; and
- (c) An emission rate of 1.9, 5.385 and 5.385 lb/MMCF for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, a lower rate is proposed for PM<sub>10</sub>, and PM<sub>2.5</sub>. The specific design of this reformer allows for a lower PM<sub>10</sub> and PM<sub>2.5</sub> emission rate. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu (approximately 2.45 lb/MMCF). The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:



- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 1.9, 5.385 and 5.385 lb/MMCF, based on a three-hour average for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

#### **Step 5: Select BACT**

IDEM has established BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for reformer furnace (EU-001) as follows:

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams; and
- (c) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall not exceed 1.9, 5.385 and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the reformer furnace (EU-001) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction (SCR)
- (b) Selective Non-Catalytic Reduction (SNCR)
- (c) Low NO<sub>x</sub> Burner (LNB)

One or more alternative methods of control may be considered when they are more cost effective than add-on controls or when add-on control may not be feasible. IDEM, OAQ and the applicant have evaluated the following alternative control methods for all combustion units in this application:

- (a) Good Combustion Practices.

These add-on control technologies and combustion control approaches are discussed below.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Selective Catalytic Reduction**

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  $\text{NO}_x$  to nitrogen and water. Under optimal conditions, SCR has removal efficiencies 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 typically operates 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 ammonia to slip through. Until the system reaches the minimum temperature, the SCR operates without ammonia injection. Above the optimum range, ammonia will oxidize to form additional  $\text{NO}_x$ . SCR efficiency is also largely dependent on the stoichiometric molar ratio of Ammonia:  $\text{NO}_x$ ; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%. Selective catalytic reduction (SCR) is a technically feasible control option for the reformer furnace (EU-001).

### **(b) Selective Non-Catalytic Reduction (SNCR)**

With selective non-catalytic reduction (SNCR),  $\text{NO}_x$  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, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the  $\text{NO}_x$  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  $\text{NO}_x$  reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms  $\text{NO}_x$  becomes significant. At a lower temperature, the rates of  $\text{NO}_x$  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  $\text{NO}_x$  control performance 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. The exhaust gases from the reformer furnace are used to preheat the influent streams to the reformer in its convection section. This reduces the reformer exhaust to 325 °F which is well below the activation temperature necessary for the reaction to begin and move to completion. The relatively low temperature of the reformer furnace flue gas renders the use of SNCR technically infeasible.

### **(c) Low $\text{NO}_x$ Burners (LNB)**

Using LNB can reduce formation of  $\text{NO}_x$  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  $\text{NO}_x$  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. The use of a low  $\text{NO}_x$  burner is a technically feasible control option for the reformer furnace (EU-001).

(d) **Good Combustion Practices / Combustion Controls**

Good combustion practices as well as operation and maintenance of the reformer furnace to keep it in good working order per the manufacturer's specifications will minimize NO<sub>x</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following control technologies have been identified and ranked for the control of NO<sub>x</sub> from the reformer furnace (EU-001).

- (a) SCR (90% Control)
- (b) Low NO<sub>x</sub> Burners (40% Control)
- (c) Good Combustion Practices (Less than 40% Control)

The applicant proposes the use of SCR along with good combustion practices and low NO<sub>x</sub> burners to control NO<sub>x</sub> emissions from the reformer furnace (EU-001). Therefore, a ranking or further analysis is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Vent	1,412.5 MMBtu/hr	0.0125 lb/MMBtu, annual average	Ultra-Low NO <sub>x</sub> Burner
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	9 ppm <sub>vd</sub> @ 3% oxygen, on a 30 day rolling average, except during startup and shutdown when the catalyst temperature is below operating range.	Good Combustion / Design, natural gas/process gas, low NO <sub>x</sub> burners, SCR
T147-32322-00062	Ohio Valley Resources	09/25/13	Methane Primary Reformer	1,006.4 MMBtu/hr	9 ppm <sub>vd</sub> on a 30 day rolling average	Good Combustion, natural gas, SCR
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr, 1,152.6 MMBtu/hr	9 ppm <sub>v</sub> on a 30 day rolling average, 56 TPY (12-mo rolling avg.)	SCR

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NM-0050	Artesia Refinery	12/14/07	Methane Reformer Heater	337 MMBtu/hr	0.0125 lb/MMBtu, 4.21 lb/hr @ 3% O <sub>2</sub> ; both 3 hr avg.	SCR
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day	0.2 lb/MMBtu; 11.93 lb/hr (3-hr, 168 rolling cumulative)	Low NO <sub>x</sub> Burner, Good Combustion

#### RBLC Review

The applicant proposes the use of SCR to control emissions of NO<sub>x</sub> to 9 ppm<sub>vd</sub> @ 3% oxygen. RBLC entries for reformers at fertilizer plants are limited and not all of the units listed directly correspond to the process proposed by Midwest Fertilizer Corporation. The Garyville Refinery reformer is based on hydrogen as a primary fuel, while the Midwest Fertilizer Corporation reformer will primarily combust natural gas. Hydrogen reformers have a cleaner fuel which results in lower emissions. The Midwest Fertilizer Corporation reformer cannot combust hydrogen without a change in process design. Therefore, the Garyville BACT will not be considered BACT for Midwest Fertilizer.

Ohio Valley Resources and the Iowa Fertilizer Company both proposed the use of SCR for control and methane as the primary fuel. Neither of these facilities have been constructed and they have not passed stack testing for NO<sub>x</sub>. However, IDEM, OAQ found NO<sub>x</sub> BACT for a reformer furnace at a nitrogenous fertilizer facility to be 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average during the PSD BACT review of the Ohio Valley Resources facility.

The Artesia Refinery BACT is a much smaller reformer and it only obtains 70% control of NO<sub>x</sub> using SCR. Also, Midwest Fertilizer Corporation will achieve a higher level of control when compared to the Pryor Plant Chemical BACT.

#### Applicant Proposal

The applicant proposes the following as BACT:

- NO<sub>x</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation; and
- NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average; and
- Work Practice Standards during SSM.

#### Step 5: Select BACT

IDEM, OAQ has established NO<sub>x</sub> BACT for reformer furnace (EU-001) as:

- NO<sub>x</sub> emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;

- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (c) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
- (d) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range; and
- (e) During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:
  - (1) **Startup:**  
Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable loaded, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its "minimum safe stable load" which is defined as that operating condition when:
    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and
    - (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
  - (2) **Shutdown:**  
Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.
  - (3) **Malfunction:**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

## CO BACT

### Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following CO control technologies for the reformer furnace (EU-001):

- (a) Regenerative Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) 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 °F to 2,000 °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 Oxidizers 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.

The use of a regenerative thermal oxidizer is not a technically feasible control option for the reformer furnace; because, the exhaust stream is comprised of natural gas combustion products with extremely low heating value. Thermal oxidizers have not been installed on natural gas combustion sources to control CO.

### **(b) 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 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 require approximately 1.5 to 2.0 ft<sup>3</sup> of catalyst per 1000 standard ft<sup>3</sup> gas flow.

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 SO<sub>2</sub> to SO<sub>3</sub> 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. The use of a catalytic oxidizer is a technically feasible control option for the reformer furnace (EU-001).

(c) **Flare**

The low heating value of the reformer furnace (EU-001) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO<sub>x</sub>. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is not a technically feasible option for the reformer furnace (EU-001).

(d) **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 reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

- (a) Oxidation Catalyst – 75% destruction efficiency
- (b) Combustion Control (Less than 75% Control)

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0194 lb/MMBtu, 3 run avg. 96.3 tons 12 month rolling	Good Combustion
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	43.45 lb/MMCF, 3 hr avg.	Good Combustion, Nat gas/process gas

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 147-32322-00062	Ohio Valley Resources	09/25/13	Primary Reformer EU-003	1,006.4 MMBtu/hr	43.45 lb/MMCF, 3 hr avg.	Good Combustion Practices, natural gas/process gas
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue	1,412.5 MMBtu/hr	0.04 lb/MMBtu 30 day rolling avg.	Proper Design, Operation and Good Engineering Practices
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer Heater	337 MMBtu/hr	0.06 lb/MMBtu, 20.22 lb/hr 3 hr average	Combust Gaseous Fuel Only
OK-0135	Pryor Plant Chemical Company	02/23/09	Primary Reformer EUID #101	700 ton ammonia per day	18.50 lb/hr, 1 hr / 8 hr	Good Combustion

## RBLC Review

A review of the RBLC entries for reformer units indicates no add-on control technology for CO has been utilized and proven cost-effective. Midwest Fertilizer Corporation presented information showing a catalytic oxidizer is economically infeasible. This is because of the large exhaust flow rate from its stack. 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<sub>x</sub>) which will at least partially offset any benefits of additional CO control. The RBLC shows CO is exclusively controlled by proper design and good combustion practice.

## Applicant Proposal

The applicant proposed the following as BACT:

- (a) CO emissions shall be controlled by the use of good combustion practices;
- (b) The reformer furnace (EU-001) shall combust natural gas and process off gases; and
- (b) CO emissions shall not exceed 43.45 lb/MMCF (0.0426 lb/MMBtu).

The applicant provided the following cost effectiveness analysis for the use of a catalytic oxidizer for CO control on the reformer furnace:

[illegible]



IDEM, OAQ has determined that the use of a catalytic oxidizer to reduce CO emissions for this emission unit is not cost effective.

The applicant's proposal is consistent with a majority of the entries in the RBLC for CO. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM, OAQ believes BACT for natural gas-fired combustion in the reformer is 43.45 lb/MMCF for CO.

#### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the reformer furnace (EU-001) as:

- (a) CO emissions from the operation of the reformer furnace (EU-001) shall be controlled by the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or off gas streams; and
- (c) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average.

#### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the reformer furnace (EU-001):

- (1) Thermal Oxidation;
- (2) Catalytic Oxidation;
- (3) Flares; and

(4) Good Combustion Practices.

Each of these control technologies is discussed in Step 2 below.

**Step 2: Eliminate Technically Infeasible Options**

(a) **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 and is considered a technology for controlling VOC emissions. Upon passing through the flame, the gas containing VOC 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 VOC/air mixture will ignite if its temperature is raised to a sufficiently high level. The VOC-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 °F to 2,000 °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 Oxidizers 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%). It is impractical for thermal oxidizers to reduce emissions of VOC from a properly operated natural gas combustion units. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a technically feasible control option for the reformer furnace (EU-001).

(b) **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 and is considered 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 the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft<sup>3</sup> of catalyst per 1,000 standard ft<sup>3</sup> gas flow.

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 SO<sub>2</sub> to SO<sub>3</sub> and subsequent combination with moisture in the

exhaust gas. The use of an oxidation catalyst to control VOC 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. Due to the lower operating temperature requirements, it is possible to use catalytic oxidizers on reformer exhaust gases. While it is physically feasible to use catalytic oxidation, it is not normally used to control VOC emissions from natural gas combustion due to excessive costs associated with raising the temperature of a low heating value gas. The use of a catalytic oxidizer for is not a technically feasible control option for the reformer furnace (EU-001).

(c) **Flare**

The low heating value of the reformer furnace (EU-001) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The use of a flare is not a technically infeasible option for the reformer furnace (EU-001).

(d) **Combustion Control**

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 VOC 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 reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has identified a single control technology for VOC control from the reformer furnace (EU-001). Therefore, no ranking is necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Reformer Furnace (EU-001) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Syngas Primary Reformer	1.13 MMCF/hr 1,152.6 MMBtu/hr	0.0014 lb/MMBtu, 3 run avg.; 6.95 ton/ 12 month rolling	Good Combustion Practices
LA-0211	Garyville Refinery	12/27/06	Hydrogen Reformer Furnace Flue Gas Vent	1,412.50 MMBtu/hr	0.0015 lb/MMBtu, 3 hr average	Proper Design, Operation and Good Combustion Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.	Proper Design, Good Combustion, natural gas / process gas

RACT/BACT/LEAR CLEARINGHOUSE DATA Reformer Furnace (EU-001) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T147-32322-00062	Ohio Valley Resources	09/25/13	Methane Primary Reformer	1,006.4 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.	Proper Design, Operation, Good Combustion, Usage Limit
OK-0134	Pryor Plant Chemical	02/23/09	Primary Reformer EUID #101	700 ton ammonia per day; 225 MMBtu/hr	1.2 lb/hr	None
OK-0135	Pryor Plant Chemical	02/23/09	Primary Reformer	700 ton ammonia per day, 225 MMBtu/hr	1.21 lb/hr	None
NM-0050	Artesia Refinery	12/14/07	Steam Methane Reformer	337 MMBtu/hr	0.0050 lb/MMBtu 1.69 lb/hr; 1 hr avg.	Combust Gaseous Fuel Only

#### RBLC Review

A review of the RBLC entries for similar units indicates add-on controls are not typical for this type of emission unit. The entries center on proper design and good combustion practices to ensure complete combustion. While the Garyville Refinery is lower, it uses a hydrogen rich fuel which is a different technology from the methane fuel used at Midwest Fertilizer Corporation, Ohio Valley Resources and the Iowa Fertilizer Company.

#### Applicant Proposal

The applicant proposed the following for BACT:

- (a) Reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (b) VOC emissions from the reformer furnace (EU-001) shall be controlled by good combustion practices and proper design; and
- (c) VOC emissions shall not exceed 5.5 lb/MMCF.

The applicant's proposal is consistent with a majority of the entries in the RBLC for VOCs. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.

- (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
- (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM, OAQ believes VOC BACT for natural gas-fired combustion in the reformer furnace (EU-001) is 5.5 lb/MMCF with the use of natural gas/process off gases and good combustion practices.

**Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the reformer furnace (EU-001) as:

- (a) VOC emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams; and
- (c) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

**Greenhouse Gas BACT**

**Step 1: Identify Potential Control Technologies**

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the reformer furnace (EU-001):

- (a) Carbon Capture and Sequestration (CCS) and Sale of CO<sub>2</sub>
- (b) Combustion of methane containing off-gas streams as fuel;
- (c) Energy Efficient Design and Combustion Practices; and
- (d) Use a low carbon fuel.

**Step 2: Eliminate Technically Infeasible Options**

- (a) **Carbon Capture and Sequestration (CCS) and Sale of CO<sub>2</sub>**  
CCS would be used to capture CO<sub>2</sub> from the exhaust, purify, compress, and transport via pipeline to either a storage location or another pipeline for use in Enhanced Oil Recovery (EOR). CCS involves four main steps as follows:
  - (1) The capture of CO<sub>2</sub> from sources including combusted exhaust streams and the CO<sub>2</sub> vent;
  - (2) The cleanup of emission streams to remove impurities to meet pipeline specifications and to compress the CO<sub>2</sub> to pipeline conditions;
  - (3) The transport of compressed CO<sub>2</sub> to a sequestration site; and
  - (4) Sequestration of the CO<sub>2</sub>.

To determine the cost effectiveness of CCS for this project, IDEM, OAQ made some best case assumptions in calculating the amount of greenhouse gases that were available for capture. IDEM, OAQ assumed all greenhouse gases generated by the facility could be cost effectively collected, concentrated to near pure carbon dioxide, and transported to the nearest pipeline for use in enhanced oil recovery. The entire source has the limited potential to emit 2,573,349 tons per year of GHG as CO<sub>2</sub>e.

After the greenhouse gas emissions have been collected and concentrated to near pure carbon dioxide, the gas must be sequestered. Sequestration can involve either injection into underground geologic formations for storage or for use in enhanced oil recovery. Sequestration for Midwest Fertilizer Corporation would require the establishment of onsite sequestration sites or the construction of a pipeline to transport the greenhouse gases to another sequestration site.

IDEM, OAQ begins its analysis of carbon capture and sequestration by determining if this control technology is feasible. When considering if a control technology is technically feasible, it must be available and applicable. A control technology is applicable if it can be reasonably be installed and operated on the source type under consideration. If a given technology has not been used on the emission unit, thought should be given on transferring technology from similar gas streams with the same physical and chemical properties.

For a technology to be considered available, consideration should be given to:

- (a) Land acquisition;
- (b) The need for federal funding;
- (c) Available transportation infrastructure; and
- (d) Developing a site for long term storage.

#### **Land Acquisition – Long Term Storage Reservoirs**

Storage reservoirs for sequestration of greenhouse gases typically use coal seams at coal mines no longer in operation, saline deposits and oil and natural gas fields. The oil industry has used carbon dioxide floods in enhanced oil recovery efforts for years. This is proven technology and is in common use today. The use of coal seams and saline deposits for underground sequestration is relatively new. This technology is still in the research phase. For Midwest Fertilizer Corporation, there are no proven sequestration sites in the local area and underground storage is not available to Midwest Fertilizer Corporation.

In regards to land acquisition for pipeline construction, Midwest Fertilizer Corporation would have to obtain easements from other entities to allow installation and future maintenance of the pipeline. These easements would be permanent and would prevent property owners from constructing permanent structures over the pipeline.

#### **Federal Funding**

In the past, grants have been available from the U.S. Department of Energy for development of carbon sequestration technologies. There are several sites in southern Indiana currently in the research phase. These projects required federal funding because the technology was prohibitively expensive for private sector participation. Midwest Fertilizer Corporation does not believe federal funding is available for this project's construction timeline.

### Available Transportation Infrastructure

Existing infrastructure to support the transportation of purified CO<sub>2</sub> off site does not exist. Therefore, transportation of the CO<sub>2</sub> stream would require the construction of a pipeline to the nearest sequestration site. The nearest pipeline to a sequestration site is located in Jackson, Mississippi and is operated by Denbury Resources, Inc. Jackson, Mississippi is located approximately 490 miles to the southwest of Mt. Vernon, Indiana, along traveled roads.

Two other projects in the Rockport, Indiana area have received construction and operation permits from IDEM, OAQ in the past year. One was for Indiana Gasification and the other was for Ohio Valley Resources. The Indiana Gasification project proposed a cross country pipeline to transport liquefied carbon dioxide to the Gulf Coast for use in enhanced oil recovery. This project has been delayed and may not be constructed. A GHG BACT analysis for the Ohio Valley Resource project showed the use of carbon capture and sequestration was not an available option. Rockport, Indiana is approximately 50 miles to the east of Mt. Vernon, Indiana. The business plans of the three facilities are completely independent of each other. The construction of the Midwest Fertilizer Corporation facility will proceed regardless of the construction of the other two facilities.

As discussed above, CCS is not feasible for Midwest Fertilizer Corporation because it is not available.

### Sale of CO<sub>2</sub>

The most practical use of captured CO<sub>2</sub> is in the oil and gas industry. CO<sub>2</sub> has been used in enhanced oil recovery for several years. An economic analysis for the Ohio Valley Resources project estimated construction costs of a CO<sub>2</sub> transmission pipeline at approximately \$250.00 per linear foot of pipe installed and approximately \$3,450,000 dollars per year in operating costs. Using the same basis, construction costs for the Midwest Fertilizer Corporation pipeline are estimated at \$646,800,000 for a 490 mile pipeline.

Control Alternative	Captured Emissions (TPY CO <sub>2</sub> e)	Emission Reduction (TPY CO <sub>2</sub> e)	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
CCS	2,573,349	2,573,349	\$646,800,000	\$3,450,000	\$92,091,384 + \$3,450,000 = \$95,541,384	\$37.13 / ton	- Taking of right of way from property owners - Land erosion from underground construction activities
Capital Recovery Factor = 0.14238 ( 7% for a 10 year life cycle)							

The capital cost for pipeline construction represents approximately 50% of the construction cost of the entire fertilizer facility. IDEM, OAQ has determined the sale of CO<sub>2</sub> is not feasible for Midwest Fertilizer Corporation because the pipeline cannot reasonably be constructed and operated by Midwest Fertilizer Corporation. Carbon capture and sequestration and sale of CO<sub>2</sub> are not technically feasible options for this facility; because, they are not available or applicable as described above.

(b) **Combustion of Methane as Fuel**

The combustion of process waste gases containing methane will destroy any methane in the streams, as well as other organic material, and generate CO<sub>2</sub>. Since methane has a higher GWP than CO<sub>2</sub>, the result is a reduction in greenhouse gas emissions as CO<sub>2</sub>e. The use of combustion of methane as fuel is considered feasible for the reformer furnace (EU-001).

(c) **Energy Efficient Design and Combustion Practices**

The use of good design and combustion practices will ensure the reformer furnace (EU-001) is operating as efficiently as possible. Efficient operation ensures emissions of greenhouse gases are minimized. Some of the design and combustion practices available to Midwest Fertilizer Corporation for use in the reformer furnace (EU-001) are:

- (1) Heat from the primary convection section of the reformer can be used to preheat the feed gas to the reformer.
- (2) The reformer could use inlet air controls to limit excess air. Limiting excess air increases combustion efficiency by reducing the amount of air that must be heated during combustion.
- (3) The reformer can be designed to achieve 80% thermal efficiency (HHV basis).
- (4) The reformer furnace can be maintained in accordance with manufacturer recommendations.

Energy efficient design and combustion practices are considered feasible for the reformer furnace (EU-001).

(d) **Use of a Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option for the reformer furnace (EU-001).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has selected all feasible control options.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Reformer Furnace (EU-001) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Reformer Furnace (EU-001)	950.6 MMBtu/hr	CO <sub>2</sub> -59.61 ton/MMCF, 3 hour avg., 486,675 ton CO <sub>2</sub> /12 month rolling and 80% Thermal Efficiency (HHV)	Good Design, Good Combustion, Use Natural Gas/Process Gas
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	Primary Reformer	1,006.4 MMBtu/hr	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. CO <sub>2</sub> emissions limited to 515,246 tons/12 month period; 90% thermal efficiency (LHV)	Good Design, Good Combustion, use natural gas/process gas
IA-0105	Iowa Fertilizer Company	10/26/12	Primary Reformer	1.13 MMCF/hr	CO <sub>2</sub> -117 lb/MMBtu, 30 day avg.; CH <sub>4</sub> - 0.0023 lb/MMBtu, N <sub>2</sub> O - 0.0006 lb/MMBtu, both 3 run avg.; CO <sub>2</sub> e - 596,905 Ton 12 month rolling	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-108 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr, 5,000,000 ton DRI/yr	CO <sub>2</sub> – 11.79 MMBtu/ton of DRI	Good Combustion Practices
LA-0248	Nucor-Direct Reduction Plant	01/27/11	DRI-208 DRI Unit #1 Reformer	12,168 billion Btu/yr, 1,389 MMBtu/hr, 5,000,000 ton DRI/yr	CO <sub>2</sub> – 11.79 MMBtu/ton of DRI	Good Combustion Practices
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Steam Methane Reformer	216 MMBtu/hr	CO <sub>2</sub> e – 183,784 Ton, 12 month rolling	Good Combustion Practices, Efficient Design

#### RBLC Review

All of the entries in the RBLC rely upon good combustion practices as the main control method for greenhouse gases. The Midwest Fertilizer Corporation proposal is typical of recently issued GHG BACT analysis for natural gas-fired reformers.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) MWF proposes the combustion of natural gas and methane containing process off-gas streams in the reformer, good design and combustion practices. MWF proposes an emission limitation of 486,675 TPY of CO<sub>2</sub>e.

The emission rates in the table above are all consistent with emission factors published in the greenhouse gas reporting rule. It appears all facilities used standard emission factors as the BACT limit for greenhouse gas emissions from the reformer furnace.

### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the reformer furnace as:

- (a) GHG emissions from the operation of reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (b) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;
- (c) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
- (d) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet steam flows;
- (e) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
- (f) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Reformer Furnace (EU-001)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the reformer furnace (EU-001) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the operation of the reformer furnace (EU-001) shall be controlled through the use of good combustion practices and proper design;
- (2) The reformer furnace (EU-001) shall combust natural gas and/or process off gas streams;

- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of reformer furnace (EU-001) shall not exceed 1.9, 5.385 and 5.385 lb/MMCF, respectively, based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
- (4) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall be controlled by low NO<sub>x</sub> burners and selective catalytic reduction (SCR) at all times the reformer is in operation, except during startup and shutdown when the catalyst is below its normal operating temperature;
- (5) NO<sub>x</sub> emissions from the reformer furnace (EU-001) shall not exceed 9 ppm<sub>vd</sub> @ 3% oxygen, based on a thirty-day rolling average, except during startup and shutdown when the catalyst temperature is below its normal operating range;
- (6) CO emissions from the reformer furnace (EU-001) shall not exceed 43.45 lb/MMCF, based on a three-hour average;
- (7) VOC emissions from the reformer furnace (EU-001) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
- (8) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 59.61 tons/MMCF, based on a three-hour average;
- (9) The reformer furnace (EU-001) shall be equipped with the following energy efficiency features: air inlet controls and flue gas heat recovery to pre-heat inlet fuel, inlet air and inlet stream flows;
- (10) The reformer furnace (EU-001) shall be designed to achieve a thermal efficiency of 80% (HHV); and
- (11) CO<sub>2</sub> emissions from the reformer furnace (EU-001) shall not exceed 486,675 tons per twelve consecutive month period with compliance determined at the end of each month.
- (12) **During periods of startup, shutdown, and malfunction, NO<sub>x</sub> emissions shall be controlled by the use of good operational practices as described below:**
  - (a) **Startup:**

Startup of the reformer furnace from cold conditions begins with the introduction of natural gas fuel to the burners and continues until the primary reformer reaches its minimum safe stable load, taking up to approximately forty-eight (48) hours. During startup, target parameters such as oxygen content, fuel/air ratios, turbulence, and temperature are variable in the convection section of the reformer furnace. The startup period ends when the reformer reaches its "minimum safe stable load" which is defined as that operating condition when:

    - (i) Convection zone parameters fall within ranges recommended by the manufacturer;
    - (ii) Catalyst tube temperatures in the radiant section have risen sufficiently to allow reforming reactions to take place; and

- (iii) The burner system has reached effective operating conditions. Good combustion practices shall be used at all times during startup.
- (b) **Shutdown:**  
Shutdown of the reformer furnace from full load requires approximately up to twenty-four (24) hours. Shutdown BACT work practice standards shall consist of good combustion practices until the completion of shutdown. The shutdown period begins when the reformer falls below its minimum safe stable load.
- (c) **Malfunction**  
During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions. Additionally, a root cause analysis of each malfunction is required to identify causes and preventive measures for each malfunction.

<b>BACT Analysis – CO<sub>2</sub> Purification Process (EU-003)</b>
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**Emission Unit Description**

- (a) One (1) 2,400 metric ton per day (MTPD) ammonia plant consisting of the following emission units:
  - (2) One (1) CO<sub>2</sub> purification process, identified as emission unit EU-003, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-003.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> PSD Applicability**

The CO<sub>2</sub> purification process does not have a potential to emit particulate. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the CO<sub>2</sub> purification process for PM, PM<sub>10</sub> and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> PSD Applicability**

The CO<sub>2</sub> purification process does not have a potential to emit NO<sub>x</sub>. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the CO<sub>2</sub> purification process for NO<sub>x</sub> and a BACT analysis is not required for these pollutants.

**CO BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for the CO<sub>2</sub> purification process (EU-003):

- (a) Optimum conversion from CO to CO<sub>2</sub> by use of a catalyst and good operational practices.

Only one control technology was identified in the RBLC. Optimum conversion is discussed below.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Optimum CO Conversion**

CO emissions can be minimized by optimum catalytic conversion of CO to CO<sub>2</sub> in the high end and low end shift converters. The use of an efficient process catalyst and good operational procedures are technically feasible control options.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The only control technology available to the CO<sub>2</sub> purification process (EU-003) is the use of an efficient catalyst and good operational procedures. The applicant has accepted the only feasible control technology. Therefore, no ranking is required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA CO <sub>2</sub> Purification Process (EU-003) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	CO <sub>2</sub> Purification Vent (EU-003)	2,646 ton ammonia per day	0.0117 lb/ton ammonia, 3 hr avg., 100% CO <sub>2</sub> venting	Use Catalyst, Good Operation Practices
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification Process EU-004	3,570 tons of CO <sub>2</sub> per day	0.0117 lb/ton ammonia, 3 hr avg.; 1,022,000 tons/12 month rolling	Use Catalyst, Good Operational Practices
IA-0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,300 ton/day Ammonia	0.02 lb/ton Ammonia, 3 run avg.; 9.65 ton/12 month rolling	Good Operational Practices
LA-0236	Donaldson Nitrogen Complex	03/03/09	#1 to #4 Carbon Dioxide Vents	Tons Ammonia/day #1/#2– 1,620 each #3/#4– 1,785 each	#1 – 5.59 lb/hr #2 – 5.59 lb/hr #3 – 5.08 lb/hr #4 – 5.95 lb/hr; 6.55 TPY	Optimum Catalytic Conversion of CO to CO <sub>2</sub>

### **RBLC Review**

Entries in the RBLC table above indicate add-on control devices are not included in the BACT determinations. The entries show BACT as the optimum conversion of CO to CO<sub>2</sub> by proper selection of a production catalyst and good operational practices. The applicant is proposing an emission rate that is the same as the recently issued Ohio Valley Resources, LLC CO BACT.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and

- (b) CO emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% venting.

The applicant is required to use the Best Available Control Technology. In this case, BACT for emission units constructed and tested is the proper selection of a production catalyst and the use of good operational practices. The applicant has proposed both control measures. In regards to the emission rate for BACT, the applicant must comply with the lowest emission rate achieved in general practice, after considering cost, energy and environmental factors. IDEM, OAQ determined BACT for the CO<sub>2</sub> purification process (EU-003) during the Ohio Valley Resources, LLC BACT determination. However, it is noted that this limit has not been demonstrated in practice and if unachievable, the BACT determination may require future revision. The applicant has accepted all control methods and the lowest emission rate.

IDEM, OAQ recognizes the emission rates proposed by Iowa Fertilizer Corporation and Ohio Valley Resources are much lower than the actual emission rate of the Donaldson Nitrogen Complex. The applicant has accepted the lower emission rate at this time. However, IDEM, OAQ may reopen the BACT for CO if the lower emission rate cannot be achieved in practice.

#### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) CO emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) CO emissions shall not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the CO<sub>2</sub> purification process (EU-003):

- (1) Thermal Oxidation;
- (2) Flares; and
- (3) Proper Selection of Process Catalyst.

Each of these control technologies is discussed below in Step 2.

#### **Step 2: Eliminate Technically Infeasible Options**

##### **(a) Thermal Oxidizers**

Regenerative thermal oxidation is effective at controlling VOC emissions and is typically used to control waste streams containing organics. Thermal oxidizers are designed to maintain a stable flame through combustion of a combination of waste gases, auxiliary fuel, and supplemental air. For the CO<sub>2</sub> vent the flow of gas to be controlled is very high and 95% of this stream is CO<sub>2</sub> with another 2% as water vapor. Neither of these constituents are combustible. Therefore, combustion of this stream to control the dilute amount of VOCs is technically infeasible.

The use of a thermal oxidizer is not a technically feasible control option for the CO<sub>2</sub> purification process (EU-003).

(b) **Flare**

The low heating value of the CO<sub>2</sub> purification process vent (EU-003) 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC.

The use of a flare is not a technically infeasible option for the CO<sub>2</sub> purification process (EU-003).

(c) **Proper Selection of Process Catalyst**

The applicant can select a process catalyst that minimizes VOC emissions while maximizing the optimum catalytic conversion of CO to CO<sub>2</sub> in the high and low shift converters. The proper selection of a low VOC catalyst is a feasible control option for the CO<sub>2</sub> purification process (EU-003).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

Only one control technology has been identified; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA CO <sub>2</sub> Purification Process (EU-003) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	CO <sub>2</sub> Purification Process (EU-003)	2,646 ton ammonia per day	0.0558 lb/ton ammonia, 3 hr avg., 100% CO <sub>2</sub> venting	Proper Catalyst, Good Operation
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification Process (EU-004)	3,570 ton CO <sub>2</sub> per day	0.0558 lb/ton ammonia, 3 hr avg.; 1,022,000 ton ammonia/12 month rolling	Low VOC Catalyst
IA-0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,012 MT/day 3,313 ton/day	0.106 lb/ton ammonia, 3 run avg.; 51.2 ton/12 month rolling	Good Operational Practices

**RBLC Review**

The RBLC has two entries for nitrogenous fertilizer facilities of similar capacities. None of the entries uses a control device for VOC. This is due to extremely low VOC emissions in the exhaust stream. The stream is nearly pure CO<sub>2</sub>.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

The applicant has accepted top BACT. However, it is noted that this limit has not been demonstrated in practice and if unachievable, the BACT determination may require future revision.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst; and
- (b) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

The following greenhouse gas (GHG) control technologies or operational practices should be evaluated for the CO<sub>2</sub> purification process (EU-003):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Sale of the Captured CO<sub>2</sub>; and
- (c) Use CO<sub>2</sub> to Manufacture Urea (Good Operational Practices).

#### **Step 2: Eliminate Technologically Infeasible Options**

- (a) **Carbon Capture and Sequestration (CCS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. IDEM, OAQ determined that CCS was not a technologically feasible option for Midwest Fertilizer Corporation because the technology was not available or applicable.
- (b) **Sale of the Captured CO<sub>2</sub>**  
Sale of the Captured CO<sub>2</sub> was evaluated for the entire source under the BACT analysis for the reformer furnace. IDEM, OAQ determined the sale of CO<sub>2</sub> was not feasible for Midwest Fertilizer Corporation because the technology was not available or applicable. Midwest Fertilizer Corporation could not reasonably construct and operate a cross county transmission pipeline to an end purchaser of the collected CO<sub>2</sub>.
- (c) **Use of CO<sub>2</sub> to Manufacturer Urea**  
The Midwest Fertilizer Corporation CO<sub>2</sub> purification process is designed to use a portion of the CO<sub>2</sub> created in the CO<sub>2</sub> purification process to manufacture urea. Good operational practices to use as much CO<sub>2</sub> in the manufacture of urea is a feasible control strategy for the CO<sub>2</sub> purification process (EU-003).



### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only technologically feasible control technology. Therefore, a ranking is not necessary. The use of CO<sub>2</sub> to produce urea reduces or eliminates the need to purchase CO<sub>2</sub> for urea production. In addition, the use of CO<sub>2</sub> to produce urea decreases the total amount vented to the atmosphere from the CO<sub>2</sub> purification vent.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
CO <sub>2</sub> Purification Process (EU-003) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA -0105	Iowa Fertilizer Company	10/26/12	CO <sub>2</sub> Regenerator	3,012 MT/day 3,313 ton/day	CO <sub>2</sub> – 1.26 ton/ton ammonia; 30 day avg.; CO <sub>2</sub> e – 1,211,847 ton /12 month rolling	Good Operational Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	CO <sub>2</sub> Purification (EU-003)	2,646 ton ammonia per day	CO <sub>2</sub> – 1.275 tons CO <sub>2</sub> per ton ammonia; 3 hr avg., 100% CO <sub>2</sub> venting; 1,232,475 ton CO <sub>2</sub> / 12 month rolling	Good Operational Practices, Usage Limit
T147-32322-00062	Ohio Valley Resources, LLC	09/25/13	CO <sub>2</sub> Purification (EU-004)	3,570 tons/day CO <sub>2</sub>	CO <sub>2</sub> – 1.275 tons CO <sub>2</sub> per ton ammonia, 3 hr avg.; 1,022,000 tons ammonia /12 month rolling	Good Operational Practices

### **RBLC Review**

The RBLC has limited entries for processes similar to the CO<sub>2</sub> purification process. In fact, there are only two facilities and neither has been built. Add-on GHG control technologies were not used. Both the Iowa Fertilizer Company and the Ohio Valley Resources facilities use good operational practices to minimize GHG emissions. The emission rate proposed by the applicant is identical to the GHG BACT issued by IDEM, OAQ for the Ohio Valley Resources facility. While the Iowa Fertilizer Corporation is slightly lower, it should be noted the processes are not identical and IDEM, OAQ determined the difference is insignificant.

### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) The applicant proposes to use CO<sub>2</sub> from the CO<sub>2</sub> purification process for the manufacture of urea while the urea unit is operating.

The applicant selected BACT as the use of CO<sub>2</sub> emissions to produce urea only while the urea unit is operating. It is important to note that Midwest Fertilizer Corporation can only use CO<sub>2</sub> from this vent when the urea unit is operating. If the urea unit is shut down and Midwest Fertilizer

Corporation chooses to make only ammonia fertilizer then venting all of the CO<sub>2</sub> would be considered BACT in this operating scenario. Midwest Fertilizer Corporation will need the flexibility to produce only ammonia fertilizer depending on market conditions. CO<sub>2</sub> emissions will be limited to 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the CO<sub>2</sub> purification process (EU-003) as:

- (a) CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;
- (b) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (c) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

IDEM, OAQ selected an emission limit based on CO<sub>2</sub> instead of CO<sub>2</sub>e; because, the gases in the CO<sub>2</sub> purification vent are comprised of greater than 99% CO<sub>2</sub>.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the CO<sub>2</sub> Purification Process (EU-003)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the CO<sub>2</sub> purification process (EU-003) shall be as follows:

- (1) CO, VOC and CO<sub>2</sub> emissions in the CO<sub>2</sub> purification process (EU-003) shall be controlled by the use of good operational procedures including the selection of an optimal process catalyst;
- (2) CO emissions from the CO<sub>2</sub> purification process (EU-003) not exceed 0.0117 lb/ton ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (3) VOC emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 0.0558 lb/ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting;
- (4) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1.275 tons of CO<sub>2</sub> per ton of ammonia produced, based on a three-hour average and 100% CO<sub>2</sub> venting; and
- (5) CO<sub>2</sub> emissions from the CO<sub>2</sub> purification process (EU-003) shall not exceed 1,232,475 tons per twelve consecutive month period with compliance determined at the end of each month.

<b>BACT Analysis – Startup Heater (EU-002)</b>
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**Emission Unit Description**

- (b) One (1) 92.5 MMBtu/hr natural gas-fired startup heater, identified as emission unit EU-002, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-002.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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:

- (a) Fuel Specifications – Clean Burning Fuel; and
- (b) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

- (a) **Cyclone**

The theory of cyclone operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The startup heater is natural gas-fired with particulate matter emissions of less than 0.005 gr/cf. The cyclone is typically used as a pretreatment device for other control devices and are used in applications with waste gas loadings between 1 and 100 gr/scf. Because the waste loading of particulate in the startup heater is already below 1 gr/scf, this technology is not feasible for the startup heater (EU-002).

(b) **Wet Scrubber**

The theory of wet scrubber operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The wet scrubber can be utilized for fine particulate control with typical loadings between 0.1 and 50 gr/scf. Once again, this technology is not feasible for the startup heater (EU-002) because the waste loading of the exhaust stream is below the level of control achievable by the scrubber.

(c) **Electrostatic Precipitators (ESP)**

The theory of electrostatic precipitator operation was discussed in detail under the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the reformer furnace and will not be repeated here. The design inlet loadings for ESPs typically range from 0.5 to 50 gr/scf. Natural gas waste loadings for particulate are well below the reduction possible by an ESP. Therefore, this technology is not feasible for the startup heater (EU-002).

(d) **Fabric Filter Dust Collectors (Baghouses)**

Baghouses are commonly used where low levels of particulate matter removal is required. A typical baghouse is capable of an outlet design concentration of 0.005 gr/cf and relies, in part on the filtering properties of a layer of particulate that first accumulates on the filter media. The outlet design concentration of the startup heater exhaust is essentially the same as the outlet emission concentration of a baghouse. In addition, a particulate layer will be difficult to develop on the filter media because of the low pollutant loading. No appreciable emission reduction can be obtained by use of a baghouse on a natural gas combustion source. Therefore, this technology is not feasible for the startup heater (EU-002).

(e) **Fuel Specifications – Clean Burning Fuel**

Clean burning natural gas has a very low potential for generating PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Fuel specifications are a technically feasible control option for the startup heater (EU-002).

(f) **Good Combustion Practices / Combustion Controls**

Good combustion practices as well as operation and maintenance of the startup heater (EU-002) to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices are a technically feasible control option for the startup heater (EU-002).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the startup heater (EU-002).

(a) Fuel Specifications – Clean Burning Fuel

(b) Good Combustion Practices / Combustion Controls

The applicant selected all control measures; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Start Up Heater (EU-002) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBL ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.0024 lb/MMBtu, 3 run avg.; 0.01 ton/12 month rolling, each	Good combustion practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.; 18.14 MMCF/12 month rolling	Good design and combustion, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Heater (EU-010)	106.3 MMBtu/hr	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 1.9, 7.6, 7.6 lb/MMCF, respectively, 3 hr avg.; 20.84 MMCF/12 month rolling	Good design and combustion, natural gas
LA-0231	Lake Charles Cogeneration	06/22/09	Methanator Startup Heater	56.90 MMBtu/hr	PM <sub>10</sub> - 0.42 lb/hr maximum	Good Design and Operation
TN-0153	Williams Refining & Marketing	04/03/02	No. 2 N/S ECU Heaters	166.5 MMBtu/hr	PM <sub>10</sub> - 0.005 lb/MMBtu (filterable)	None
TN-0153	Williams Refining & Marketing	04/03/02	WCR Heater	209.0 MMBtu/hr	PM <sub>10</sub> - 0.005 lb/MMBtu (filterable)	None

#### RBL Review

The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) result from the combustion of natural gas. PM/PM<sub>10</sub>/PM<sub>2.5</sub> from the startup heater (EU-002) will result in a particulate concentration in the exhaust of 0.005 grains/dscf or less. This low concentration renders add-on controls infeasible. Generally add-on controls for PM, PM<sub>10</sub> and PM<sub>2.5</sub> are not applied to a combustion source firing only clean gaseous fuel. This is because the PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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.

A search of the USEPA's RACT/BACT/LAER Clearinghouse database did not indicate control technologies for PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions from natural gas-fired heaters are used. The combustion of clean gaseous fuel is inherently low in particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>) emissions and add-on controls are not feasible. IDEM, OAQ anticipates the lowest uncontrolled emission rate of a natural gas fired heater will be 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and 1.9 lb/MMCF for PM. The Williams Refining & Marketing process heaters have an emission limit of 0.005 lb/MMBtu but only includes filterable PM<sub>10</sub> and PM<sub>2.5</sub>. When condensable emissions are considered, the emission rate is identical to the emission rate proposed by the applicant. The Iowa Fertilizer Company emission rate is the lowest entry for a natural gas fired process heater.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The use of natural gas;
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively;
- (c) The startup heater shall not combust in excess of 18.14 MMCF of natural gas in a twelve consecutive month period, with compliance determined at the end of each month; and
- (d) Good heater design and good combustion practices.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM<sub>10</sub>, and PM<sub>2.5</sub>. These emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

IDEM is proposing an emission rate of 1.9, 7.6 and 7.6 lb/MMCF for PM, PM<sub>10</sub> and PM<sub>2.5</sub>, respectively.

### **Step 5: Select BACT**

IDEM has established BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following NO<sub>x</sub> control technologies for the startup heater (EU-002):

- (a) Selective Catalytic Reduction (SCR)
- (b) Selective Non-Catalytic Reduction (SNCR)
- (c) Low NO<sub>x</sub> Burner (LNB)
- (d) Flue Gas Recirculation (FGR)
- (e) Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)
- (f) No Control

NO<sub>x</sub> add-on control technologies are discussed below:

### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Selective Catalytic Reduction (SCR)**  
The theory of operation of an SCR unit was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. SCR has been installed on process heaters and boilers for many years. Therefore, selective catalytic reduction (SCR) is a technologically feasible control option for the startup heater (EU-002).
- (b) **Selective Non-Catalytic Reduction (SNCR)**  
The theory of operation of an SNCR unit was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. SNCR requires the employment of an injection system that can accomplish thorough reagent / gas mixing within a narrow temperature range while accommodating temperature variation in the exhaust stream. This technology requires relatively stable steady-state operation within a narrow temperature range. Given the standby nature of this process heater, selective non-catalytic reduction is not a technically feasible control option for the startup heater (EU-002).
- (c) **Low NO<sub>x</sub> Burner (LNB)**  
The theory of operation of low NO<sub>x</sub> burners was discussed under the reformer furnace NO<sub>x</sub> BACT and will not be repeated here. NO<sub>x</sub> emission reductions can be realized using low NO<sub>x</sub> burners in natural gas-fired combustion sources. The use of low NO<sub>x</sub> burners is a feasible control option for the startup heater (EU-002).
- (d) **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 NO<sub>x</sub> production. Flue gas recirculation (FGR) can be a highly effective technique for lower NO<sub>x</sub> emissions from burners and it is 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 NO<sub>x</sub> emissions to a little as 25% of their normal levels. FGR lowers NO<sub>x</sub> emissions by: the cooler, relatively inert, recirculated flue gases act as a 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 NO<sub>x</sub> forming reactions of one of the needed ingredients. FGR has been used on natural gas-fired boilers and process heaters and it is a technically feasible control option for the startup heater (EU-002).

- (e) **Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)**  
Low NO<sub>x</sub> burners can be combined with flue gas recirculation to achieve an even higher level of control than each can provide individually. The combination of FGR and low NO<sub>x</sub> burners are a technologically feasible control option for the startup heater (EU-002).
- (f) **No Control Option**  
The no control option is where no add-on controls are proposed to control NO<sub>x</sub> from the startup heater (EU-002). This option is usually feasible in the case of emission units that have extremely low emissions or extremely low hours of operation that make the use of add-on controls impractical. The use of the no control option is a technically feasible control option for the startup heater (EU-002).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following control technologies are available for NO<sub>x</sub> control for the startup heater (EU-002). They are ranked in order of control efficiency:

- (a) Selective Catalytic Reduction (90% Control)
- (b) Low NO<sub>x</sub> Burners with Flue Gas Recirculation (55% to 60% Control)
- (c) Low NO<sub>x</sub> Burners (50% Control)
- (d) Flue Gas Recirculation (25% Control)
- (e) No Control Option (0% Control)

The applicant has selected a no control option as BACT. As such, a technical, environmental and economic analysis is normally performed. In this case, IDEM, OAQ is not requiring further analysis because this emission unit will only operate 200 hours a year and the use of add-on controls would be impractical.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Startup Heater (EU-002) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110 MMBtu/hr	0.119 lb/MMBtu, 3 run avg.; 0.63 ton/12 month rolling	Good Combustion Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	183.70 lb/MMCF, 3 hr avg., 18.14 MMCF/12 month rolling	Good Design and Combustion, Natural Gas



<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Startup Heater (EU-002) – NO<sub>x</sub></b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Startup Heater (EU-010)	106.3 MMBtu/hr	183.70 lb/MMCF, 3 hr avg., 20.84 MMCF/12 month rolling	Good Design and Combustion, Natural Gas
LA-0244	Sasol N.A., Inc.	11/29/10	Natural Gas Charge Heater	87.3 MMBtu/hr	7.15 lb/hr, maximum	Low NO <sub>x</sub> Burners
LA-0244	Sasol, N.A., Inc.	11/29/10	Oil Heater	170 MMBtu/hr	19.69 lb/hr, maximum	Low NO <sub>x</sub> Burners
LA-0262	Cornerstone Chemical Company	05/03/12	Startup Heater	61 MMBtu/hr	10.15 lb/hr, maximum; 1.73 TPY maximum	Good Engineering Design

#### **RBLC Review**

The startup heater (EU-002) is intended to be used by the source for a maximum of 200 hours per year for plant startup. The limited amount of use of this heater makes the use of add-on controls impractical. The unrestricted potential to emit NO<sub>x</sub> of the startup heater is 48.62 TPY. The limited potential to emit based on 200 hours of operation is 1.11 TPY. NO<sub>x</sub> emissions from these units are best controlled by good combustion practices.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) NO<sub>x</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

The lowest emission rate indicated in the RBLC is 0.08 lb/MMBtu. Midwest Fertilizer Corporation is proposing an emission rate of 0.18 lb/MMBtu and an annual limit of 200 hours of operation. If the Midwest Fertilizer Corporation was to accept a BACT limit of 0.08 lb/MMBtu without a limit on the hours of operation, the startup heater would emit 32.41 tons of NO<sub>x</sub> per year. If the applicant's proposal is accepted, the startup heater would emit 1.67 tons of NO<sub>x</sub> per year. So while the emissions on an hourly rate are higher, the annual rate is much lower and represents a higher level of control.

#### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) NO<sub>x</sub> emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average.

#### **CO BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following CO control technologies for the startup heater (EU-002):

- (a) Regenerative Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

Each of the control technologies is discussed below.

#### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Regenerative Thermal Oxidizer (RTO)**  
The theory of operation of the regenerative thermal oxidizer was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The use of an RTO is not a technologically feasible control option for the startup heater (EU-002). Thermal oxidation is not normally used to control CO in the exhaust streams of natural gas combustion. The combustion products have a low heating value that makes the use of a thermal oxidizer impractical.
- (b) **Catalytic Oxidation**  
The theory of catalytic oxidation was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The use of an oxidation catalyst to control carbon monoxide emissions is feasible for natural gas-fired combustion units because the fuel is low in sulfur with relatively low concentrations of other contaminants, such as metals. The use of catalytic oxidation is a technically feasible control option for the startup heater (EU-002).
- (c) **Flares**  
The theory of operation of flares was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. The heating value of the startup heater's exhaust is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require significant addition of supplemental fuel. Therefore, a secondary impact of the use of a flare for this waste stream would be the creation of additional emissions from burning supplemental fuel, including NO<sub>x</sub>. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. The use of a flare is a technically infeasible option for CO control from the startup heater (EU-002).

(d) **Combustion Control**

The theory of combustion control was discussed in detail under the CO BACT for the reformer furnace and it will not be repeated here. 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 startup heater.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

- (a) Oxidation Catalyst – 75% destruction efficiency
- (b) Combustion Control

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Startup Heater (EU-002) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	0.0194 lb/MMBtu, 3 run avg.; 0.1 ton/12 month rolling	Good Combustion
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu, 7.4 TPY	Good Combustion
MD-0035	Dominion Cove Pt.	08/12/05	Vaporization Heater	88.4 MMBtu/hr	0.03 lb/MMBtu	Good Combustion, Good Operations, Natural Gas
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	37.23 lb/MMCF, 3 hr avg. 18.14 MMCF/12 month rolling	Good Combustion, Good Operations, Good Design, Natural Gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Catalyst Heater EU-010	106.3 MMBtu/hr	37.23 lb/MMCF, 3 hr avg.; 20.84 MMCF/12 month rolling	Good Combustion, Good Operations, Good Design, Natural Gas

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Startup Heater (EU-002) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
OK-0136	Conoco Phillips	02/09/09	Crude Heater	125 MMBtu/hr	5.0 lb/hr and 21.9 TPY, 365 day rolling; 0.04 lb/MMBtu	Ultra Low NOx Burners and Good Combustion
MN-0070	Minnesota Steel Industries	09/07/07	Process Heaters	606 MMBtu/hr	0.08 lb/MMBtu, 1 hr rolling; 50 lb/hr, 1 hr rolling	None

#### RBLC Review

A review of CO BACT analysis for natural gas-fired process heaters in the RBLC shows add-on control technology is not practical. CO emissions are controlled exclusively by good combustion practices and limits on the operation of the combustion unit. As noted earlier, catalytic oxidation is not a cost effective CO emission control system for the reformer furnace. Because of the lower utilization of the startup heater and lower CO emissions, it is even less cost-effective to use catalytic oxidation for the startup heater. In addition, the use of a thermal or catalytic oxidizer for CO control would require significant supplemental fuel resulting in additional CO emissions. The emission rate proposed by Midwest Fertilizer Corporation is identical to the recently issued Ohio Valley Resource permit. It is comparable to the Dominion Cove Pt. heater and only two entries are lower.

#### Applicant Proposal

The applicant proposed the following for BACT:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) CO emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

The applicant's proposal is consistent with or lower than a majority of the entries in the RBLC for CO emissions. Midwest Fertilizer Corporation's emission limits are based on the uncontrolled emission factors found in AP-42. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0194 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.

- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility – a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

The next lowest entry in the RBLC for CO from a startup heater is 0.02 lb/MMBtu from the Williams Field Services Oil Heater in Wyoming. If Midwest Fertilizer Corporation accepted the lower emission rate without the limit on the hours of operation, the startup heater would emit 8.1 tons CO per year. If the applicant's proposal of 0.0365 lb/MMBtu with a 200 hour per year operational limit is accepted, the startup heater would emit 0.34 tons of CO per year. With 0.34 ton/year of CO emissions, add-on controls needed to achieve 0.02 lb CO/MMBtu is not cost effective. While the hourly emission rate would be lower at 0.02 lb CO/MMBtu, the applicant's proposal represents an overall lower annual emission rate and represents BACT for this unit.

**Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) CO emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average.

**VOC BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following VOC control technologies for the Ammonia Catalyst Startup Heater (EU-002):

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Good Combustion Practices.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Thermal Oxidation**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. Generally, it is impractical for thermal oxidizers to reduce VOC emissions from a properly operated natural gas-fired combustion unit. This is due to the large energy input required to obtain the required destruction temperature because the exhaust stream lacks adequate fuel. The use of a thermal oxidizer is not a feasible control technology for the startup heater (EU-002).

(b) **Catalytic Oxidation**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. Much like the thermal oxidizer, a catalytic oxidizer uses high temperatures in the presence of a catalyst to combust VOC in the exhaust stream. This works for exhaust streams with significant organic content. The exhaust stream from the startup heater does not contain sufficient organic material to support combustion and a large amount of additional combustion fuel is required. The use of a catalytic oxidizer is not a technologically feasible control option for the startup heater (EU-002).

(c) **Flares**

A discussion of the theory of operation of this control technology was presented under the VOC BACT for the reformer furnace and will not be repeated here. The low heating value of the startup heater 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 a flare for this stream would be the creation of additional emissions from burning supplemental fuel, including VOC. The VOC emissions created by this unit are due to natural gas combustion, additional natural gas would increase VOC emissions. The use of a flare is not a technically infeasible option for the startup heater (EU-002).

(d) **Good Combustion Practices**

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 VOC 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 startup heater (EU-002).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The only conventional VOC control technology that is technologically feasible for the startup heater (EU-002) is good combustion practices. A ranking is not necessary.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Ammonia Catalyst Startup Heater (EU-002) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	0.0014 lb/MMBtu, 3 run avg.; 0.01 ton / 12 month rolling	Good Combustion Practices
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.; 18.14 MMCF/12 month rolling	Good Combustion, Good Design, Natural Gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Catalyst Startup Heater (EU-010)	106.3 MMBtu/hr	5.5 lb/MMCF, 3 hr avg. 20.84 MMCF/12 month rolling	Good Combustion Good Design Natural Gas
OH-0329	BP Products Husky Refining	08/07/09	Reformer Heater	519 MMBtu/hr	2.8 lb/hr; 12.28 ton/12 month rolling; 5.5 lb/MMCF	None
LA-0197	Conoco Phillips, Alliance	07/21/09	Gasoline Feed Heater	138.12 MMBtu/hr	0.74 lb/hr maximum, 2.72 TPY maximum	Good Combustion Good Engineering
WY-0067	Williams Field Services	04/01/09	Hot Oil Heater	84 MMBtu/hr	0.02 lb/MMBtu 7.0 TPY	Good Combustion
OK-0134	Pryor Plant Chemical Company	02/23/09	Nitric Acid Preheaters	20 MMBtu/hr	0.11 lb/hr	Good Combustion
SC-0115	GP Clarendon LP	02/10/09	Backup Oil Heater	75 MMBtu/hr	0.39 lb/hr; 1.72 TPY	Good Combustion

#### **RBLC Review**

None of the process heater listed in the RBLC used an add-on control device for VOC control. VOC emissions were controlled by good combustion practice.

### **Applicant Proposal**

The applicant proposed the following as VOC BACT:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) VOC emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average.

The applicant's proposal is consistent with a majority of the entries in the RBLC and with recent BACT determinations from IDEM, OAQ. The emission limit proposed by Midwest Fertilizer is based on the AP-42 emission factor for natural gas combustion. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) with a proposed emission rate of 0.0014 lb/MMBtu. The IFC permit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM, OAQ believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility -- a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas;
- (b) VOC emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average.



## **Greenhouse Gas BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas control technologies for the startup heater (EU-002):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices; and
- (c) Low Carbon Fuel.

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ has evaluated each of the Step 1 technologies for the startup heater (EU-002) below:

- (a) **Carbon Capture and Sequestration (CSS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. The startup heater is used during plant startup to preheat the ammonia catalyst until a temperature is reached where the reaction is self-sustaining. The unit will operate for a maximum 200 hours per year for startups and maintenance. As was discussed in detail under the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology for the startup heater (EU-002).
- (b) **Good Design and Combustion Practices**  
The proper design, operation, and maintenance of the startup heater will ensure optimal operation and the minimization of greenhouse gas emissions. Operation of the heater can be controlled by the use of inlet air control sensors that limit excess air and result in optimal combustion. Good design and combustion practices are a technologically feasible control technology for the startup heater (EU-002).
- (c) **Low Carbon Fuel**  
The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of low carbon fuel such as natural gas is a technologically feasible control option for the startup heater (EU-002).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has selected all technically feasible control options for the startup heater (EU-002). Therefore, there is no need to rank the control options.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Catalyst Startup Heater (EU-002) – Greenhouse Gases						
RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Startup Heater (EU-002)	92.5 MMBtu/hr	CO <sub>2</sub> - 59.61 tons/MMCF, 3 hr avg., 18.14 MMCF/12 month rolling	Good Combustion, Good Design, Natural Gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Startup Heater (EU-010)	106.3 MMBtu/hr	CO <sub>2</sub> - 59.61 tons/MMCF, 3 hr avg., 20.84 MMCF/12 month rolling	Good Combustion, Good Design, Natural Gas
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, 3 run avg.; CH <sub>4</sub> -0.0023 lb/MMBtu, 3 run avg.; CO <sub>2</sub> e – 638 ton/12 month rolling; N <sub>2</sub> O – 0.0006 lb/MMBtu, 3 run average	Good Combustion

#### RBLC Review

Due to the intermittent operation of these startup heaters, add-on control devices are not practical. All similar units in the RBLC use a combination of low carbon fuel, proper design, good combustion practices and limits on the hours of operation.

#### Applicant Proposal

The applicant proposes the following for GHG BACT for the startup heater (EU-002):

- The startup heater (EU-002) shall combust natural gas.
- GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

The applicant has proposed top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the startup heater (EU-002) as:

- (a) The startup heater (EU-002) shall combust natural gas.
- (b) GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices.
- (c) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (d) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Startup Heater (EU-002)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the startup heater (EU-002) shall be as follows:

- (1) The startup heater (EU-002) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the startup heater (EU-002) shall be controlled by good heater design and good combustion practices;
- (3) Natural gas usage in the startup heater (EU-002) shall not exceed 18.14 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the startup heater (EU-002) shall not exceed 1.9, 7.6, and 7.6 lb/MMCF, respectively based on a three-hour average. PM includes filterable particulate matter, while, PM<sub>10</sub> and PM<sub>2.5</sub> include both filterable and condensable particulate matter;
- (5) NO<sub>x</sub> emissions from the startup heater (EU-002) shall not exceed 183.70 lb/MMCF, based on a three-hour average;
- (6) CO emissions from the startup heater (EU-002) shall not exceed 37.23 lb/MMCF, based on a three-hour average;
- (7) VOC emissions from the startup heater (EU-002) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (8) CO<sub>2</sub> emissions from the startup heater (EU-002) shall not exceed 59.61 ton/MMCF, based on a three-hour average.

### BACT Analysis – Front End Flare (EU-017)

#### Emission Unit Description

- (c) One (1) 4.0 MMBtu/hr Front End Flare, using a natural gas-fired pilot, identified as emission unit EU-017; approved for construction in 2014, used to control intermittent process gas emissions from maintenance, startup, shutdown, and malfunctions, exhausting to stack S-017.

#### PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT

##### **Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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:

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

##### **Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

- (a) **Flare design and good combustion practices**  
Flare design and operation are key elements in the emissions performance of flares. The front end flare (EU-017) 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 use of flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).
- (b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the front end flare (EU-017).
- (c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (a) Proper flare design and good combustion practices; and
- (b) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Front End Flare (EU-017) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	PM–0.0019 lb/MMBtu PM <sub>10/2.5</sub> –0.0075 lb/MMBtu, 3 hr average	Good combustion practice/flare design, flare minimization plan, nat gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	PM–0.0019 lb/MMBtu PM <sub>10/2.5</sub> –0.0075 lb/MMBtu, 3 hr average	Proper design and operation, low carbon fuel, flare minimization practices
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Smokeless Flare; Good Combustion; VE notations by Method 22
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

### **RBLC Review**

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42, Chapter 1.4 emission factor. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

### **Applicant Proposal**

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of Pm and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for front end flare (EU-017):

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the front end flare (EU-017):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the front end flare (EU-017).
- (b) **Process flaring minimization practices**  
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).
- (c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:
  - (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Front End Flare (EU-017) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	0.068 lb/MMBtu, pilot and 595.49 lb/hr venting, 3 hr average, Venting not to exceed 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	0.068 lb/MMBtu, pilot and 595.49 lb/hr venting, venting not to exceed 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion

**RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.



### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (e) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.
- (f) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the front end flare (EU-017):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

#### **(a) Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).

#### **(b) Process flaring minimization practices**

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. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).

#### **(c) 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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Front End Flare (EU-017) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	0.37 lb/MMBtu, 3,240.16 lb/hr venting, based on 3 hour average, 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	0.37 lb/MMBtu, pilot and 3,240.16 lb/hr, venting, 3 hr average, 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from process, no limit on pilot	None

**RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

**Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the front end flare (EU-017) shall be controlled by good combustion practices;
- (b) CO emissions from the front end flare (EU-017) shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by the use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, while venting, based on a three-hour average.
- (f) Venting to the front end storage flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

**VOC BACT**

**Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the front end flare (EU-017):

- (a) Flare Design and Monitoring;
- (b) Process Flaring Minimization Practices; and
- (c) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the front end flare (EU-017).

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the front end flare (EU-017).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the front end flare (EU-017).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Front End Flare (EU-017) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	0.0054 lb/MMBtu, pilot and 47.26 lb/hr, venting 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare (EU-007)	37.741 MMBtu/hr	0.0054 lb/MMBtu, pilot and 47.26 lb/hr, venting 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

#### RBLC Review

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

#### Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:

- (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
- (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr during venting, based on a three-hour average.
- (f) Venting of emissions to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the front end flare (EU-017):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices;
- (c) Flare Minimization practices (FMP); and
- (d) Low Carbon Fuel for Pilot and Sweep Gas.

#### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Carbon Capture and Sequestration (CCS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. Greenhouse gas emissions from the front end flare (EU-017) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the front end flare (EU-017).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the front end flare (EU-017).

(d) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Front End Flare (EU-017) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Front End Flare (EU-017)	4.0 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 511.81 ton/hr, venting, 3 hr average; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Front End Process Flare EU-007	37.741 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 511.81 ton/hr, 3 hr average; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas



RACT/BACT/LEAR CLEARINGHOUSE DATA Front End Flare (EU-017) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr and 4,852 TPY; CH <sub>4</sub> -0.06 lb/hr and 0.08 TPY; N <sub>2</sub> O-0.05 lb/hr and 0.08 TPY	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY maximum	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY Maximum	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### Applicant Proposal

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

#### Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the front end flare (EU-017) as:

- (a) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the Ammonia Unit;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and

- (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (e) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, during venting, based on a three-hour average.
- (f) Venting emissions to front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Front End Flare (EU-017)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the front end flare (EU-017) shall be as follows:

- (1) The pilot and purge gas fuels used in the front end flare (EU-017) shall be natural gas.
- (2) Venting to the front end flare (EU-017) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events.
  - (A) Flare Use Minimization: Process syngas streams to flare EU-017 shall not contain ammonia. During the startup of the sequential reformer, only one process stream at a time shall be sent to the flare to the extent practicable. Maximize the use of process syngas during the startup of the ammonia unit;

- (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
    - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
    - (B) Flares shall be operated with a flame present at all times; and
    - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
  - (5) PM emissions from the front end flare (EU-017) shall not exceed 1.9 lb/MMCF, based on a three-hour average.
  - (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the front end flare (EU-017) shall each not exceed 7.6 lb/MMCF, based on a three-hour average.
  - (7) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
  - (8) NO<sub>x</sub> emissions from the front end flare (EU-017) shall not exceed 595.49 lb/hr, during venting operations, based on a three-hour average.
  - (9) CO emissions from the front end flare (EU-017) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
  - (10) CO emissions from the front end flare (EU-017) shall not exceed 3,240.16 lb/hr, during venting, based on a three-hour average.
  - (11) VOC emissions from the front end flare (EU-017) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
  - (12) VOC emissions from the front end flare (EU-017) shall not exceed 47.26 lb/hr, during venting, based on a three-hour average.
  - (13) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
  - (14) CO<sub>2</sub> emissions from the front end flare (EU-017) shall not exceed 511.81 ton CO<sub>2</sub>/hr, while venting, based on a three-hour average.

<b>BACT Analysis – Back End Flare (EU-018)</b>
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**Emission Unit Description**

- (d) One (1) 4.0 MMBtu/hr Back End Flare, using a natural gas-fired pilot, identified as emission unit EU-018, approved for construction in 2014, exhausting to stack S-018.

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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:

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

**Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

- (a) **Flare design and good combustion practices**  
Flare design and operation are key elements in the emissions performance of flares. The back end flare (EU-018) 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 use of flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).
- (b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the back end flare (EU-018).
- (c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (a) Proper flare design and good combustion practices; and
- (b) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b> <b>Back End Flare (EU-018) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Back End Flare (EU-018)	4.0 MMBtu/hr	PM-0.0019 lb/MMBtu PM <sub>10/2.5</sub> -0.0075 lb/MMBtu	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare EU-006	38.264 MMBtu/hr	PM-0.0019 lb/MMBtu PM <sub>10/2.5</sub> -0.0075 lb/MMBtu	Good combustion practice/flare design, flare minimization plan, natural gas
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Smokeless, good combustion, VE by method 22
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

### **RBLC Review**

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42, Chapter 1.4 emission factor. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

### **Applicant Proposal**

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for back end flare (EU-018):

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

## **NO<sub>x</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the back end flare (EU-018):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the back end flare (EU-018).
- (b) **Process flaring minimization practices**  
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).
- (c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:
  - (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Back End Flare (EU-018) -- NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Back End Flare (EU-018)	4.0 MMBtu/hr	0.068 lb/MMBtu pilot, and 624.94 lb/hr venting, 3 hr average; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Flare EU-006	38.264 MMBtu/hr	0.068 lb/MMBtu, pilot and 624.94 lb/hr venting, 3 hr average; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black Plant	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion and Meet 40 CFR 60.18
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

**RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.



**Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

The applicant proposed top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.

- (e) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the back end flare (EU-018):

- (a) Flare design and good combustion practices;
- (b) Process flaring minimization practices; and
- (c) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).
- (b) **Process flaring minimization practices**  
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. The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).
- (c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:
  - (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
  - (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Back End Flare (EU-018) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Back End Flare (EU-018)	4.0 MMBtu/hr	0.37 lb/MMBtu pilot and 804.76 lb/hr venting, 3 hr avg.; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare EU-006	38.264 MMBtu/hr	0.37 lb/MMBtu, pilot and 804.76 lb/hr, venting, 3 hr avg.; 336 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion and Meet 40 CFR 60.18

### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the back end flare (EU-018) shall be controlled by good combustion practices;
- (b) CO emissions shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by the use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.

- (e) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

### **VOC BACT**

#### **Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the back end flare (EU-018):

- (a) Flare Design and Monitoring;
- (b) Process Flaring Minimization Practices; and
- (c) Flare Gas Recovery.

Each of these VOC control technologies are evaluated below in Step 2.

#### **Step 2: Eliminate Technically Infeasible Options**

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the back end flare (EU-018).

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option for the back end flare (EU-018).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the back end flare (EU-018).

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b>						
<b>Back End Flare (EU-018) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Back End Flare (EU-018)</b>	<b>4.0 MMBtu/hr</b>	<b>0.0054 lb/MMBtu, pilot and 11.73 lb/hr venting, 3 hr avg. and 336 hr/12 month rolling</b>	<b>Good combustion practice/flare design, flare minimization plan, natural gas</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Process Flare (EU-006)	38.264 MMBtu/hr	0.0054 lb/MMBtu, pilot and 11.73 lb/hr, venting, 3 hr avg. and 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles Refinery	11/17/09	Flare 1 – 5	Not Specified	No Limits	Comply with 40 CFR 63, Subpart A

#### **RBLC Review**

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

**Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (e) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

**Greenhouse Gas BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the back end flare (EU-018):

- (a) Carbon Capture and Sequestration (CCS);
- (b) Good Design and Combustion Practices;
- (c) Flare Minimization practices (FMP); and
- (d) Low Carbon Fuel for Pilot and Sweep Gas.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT for the reformer furnace. Greenhouse gas emissions from the back end flare (EU-018) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

### **(b) Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the back end flare (EU-018).

### **(c) Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the back end flare (EU-018).

### **(d) Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas is a feasible control option.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Back End Flare (EU-018) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Back End Flare (EU-018)	4.0 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 127.12 ton/hr venting, 3 hr average and 336 hr/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Back End Flare Process Flare EU-006	38.264 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, pilot and 127.12 ton/hr, venting	Good combustion practice/flare design, flare minimization plan, natural gas
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr and 4,852 ton/12 month rolling; CH <sub>4</sub> -0.06 lb/hr and 0.08 ton/12 month rolling; N <sub>2</sub> O-0.05 lb/hr and 0.08 ton/12 month rolling.	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY, maximum	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY, maximum	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### Applicant Proposal

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the back end flare (EU-018) as:

- (a) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (e) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.
- (f) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

**Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Back End Flare (EU-018)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the back end flare (EU-018) shall be as follows:

- (1) The pilot and purge gas fuels used in the back end flare (EU-018) shall be natural gas.
- (2) Venting to the back end flare (EU-018) shall not exceed 336 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: Flare EU-018 shall be limited to flaring ammonia during high-pressure events to the extent practicable. The ammonia compressor main shall be depressurized prior to compressor maintenance. The Permittee shall limit venting ammonia rich streams to Flare EU-018 to the extent practicable during non-emergency startup and shut down operations;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) PM emissions from the back end flare (EU-018) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the back end flare (EU-018) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
- (7) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.

- (8) NO<sub>x</sub> emissions from the back end flare (EU-018) shall not exceed 624.94 lb/hr, during venting, based on a three-hour average.
- (9) CO emissions from the back end flare (EU-018) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) CO emissions from the back end flare (EU-018) shall not exceed 804.76 lb/hr, during venting, based on a three-hour average.
- (11) VOC emissions from the back end flare (EU-018) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (12) VOC emissions from the back end flare (EU-018) shall not exceed 11.73 lb/hr, during venting, based on a three-hour average.
- (13) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.
- (14) CO<sub>2</sub> emissions from the back end flare (EU-018) shall not exceed 127.12 lb/hr, during venting, based on a three-hour average.

<b>BACT Analysis – Urea Granulation Unit (EU-008)</b>
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**Emission Unit Description**

- (e) One (1) 1,440 metric ton per day Urea Granulation Unit, identified as EU-008, approved for construction in 2014, particulate emissions are controlled by a high efficiency wet scrubber, exhausting to stack S-008. [40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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**

The theory of operation of a cyclone was discussed in detail in the particulate BACT for the reformer and will not be repeated here. Granulated urea is created in the granulation unit by spraying a heated liquid into a fluidized bed containing fine granules. The urea coats the particles until they reach the desired diameter. The hot urea granules are sticky until completely cooled. Cyclones rely on particulate matter to fall out of the gas stream when they impact the wall of the control device. Because the granules are sticky, they will collect on the walls of the cyclone instead of falling into the collection hopper. This will cause the unit to foul on a frequent basis. Therefore, a cyclone is not a feasible control technology for this waste gas stream.

(b) **Wet Scrubbers**

The urea granules created in the granulation unit are hygroscopic. They tend to attract water in the air. This physical property makes wet scrubbers an ideal control device. Therefore, wet scrubbing is a technologically feasible control technology.

(c) **Electrostatic Precipitators (ESP)**

Electrostatic precipitators impart a negative electric charge to particulate in the waste gas stream and a positive charge to the collector plates. The difference in electrical charge results in particulate being attracted to the collection plates. Collected particulate matter is typically removed during a cleaning cycle by rapping. A process whereby a vibration is used to dislodge the charged particles. Because of the physical characteristics of this waste gas stream, the charged particles will become stuck to the walls of the control device. This will reduce collection efficiency and will result in excessive maintenance problems. The use of an electrostatic precipitator is not a technologically feasible control technology for this application.

(d) **Fabric Filter Dust Collectors (Baghouses)**

Baghouses use a fabric filter to physically separate particulate from the waste gas stream. This method of operation is not compatible with the sticky physical properties of the hot urea granule. Fouling will cause excessive maintenance problems. Therefore, this is not a technologically feasible control technology for this application.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only technologically feasible control technology for the urea granulation unit (EU-008). Therefore, a ranking is not needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Urea Granulator (EU-008) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0106	CF Industries Nitrogen, LLC	07/18/13	Urea Granulator	176.46 ton urea/hr (4,235 ton/day)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> 0.11 lb /ton urea, 3 run avg. and 85.7 ton/12 month rolling	Wet Scrubber Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Urea Granulator (EU-008)	1,587 tons urea/day	PM/PM <sub>10</sub> , PM <sub>2.5</sub> – 0.163 lb/ton urea	Wet Scrubber 90% Control
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granulator	1,500 metric ton urea/day	0.10 kg PM/MT 0.10 kg PM <sub>10</sub> /MT 0.025 kg PM <sub>2.5</sub> /MT, 3 run avg.; PM/PM <sub>10</sub> – 60.4 ton/12 month rolling; PM <sub>2.5</sub> – 15.1 ton/12 month rolling	Wet Scrubber
OK-0124	Koch Nitrogen Company	04/09/09	Urea Granulator	1,550 ton urea/day	6.6 lb/hr PM <sub>10</sub>	Wet Scrubber 90% Control

#### RBLC Review

Urea granulation units are typically controlled by a wet scrubber. This is due to the physical characteristics of the hot urea granules. The only facility in the above table that has been constructed is the Koch Nitrogen Company facility near Enid, Oklahoma. A stack test of the urea granulator indicates PM/PM<sub>10</sub> emissions from the unit are approximately 0.3 lb/ton. The applicant is proposing an emission rate of 0.163 lb/ton PM, PM<sub>10</sub> and PM<sub>2.5</sub>, each. This is the lowest emission rate of any facility which has been constructed and demonstrated in practice.

#### Applicant Proposal

The applicant proposed the following for BACT:

- The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall not exceed 0.163 lb per ton granules, each.

The applicant's proposal is significantly below the only RBLC entry for a facility that has been constructed and stack tested. As such, IDEM, OAQ accepts the applicant's proposal as BACT for the urea granulator.

#### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for the urea granulation unit (EU-008) as:

- (a) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall not exceed 0.163 lb per ton granules, each, based on a three-hour average.

#### **NO<sub>x</sub>, CO and GHG PSD Applicability**

The urea granulation unit (EU-008) does not have the potential to emit NO<sub>x</sub>, CO, and GHG. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea granulation unit for these pollutants and a BACT analysis is not required for these pollutants.

#### **VOC PSD Applicability**

The urea granulation unit (EU-008) has a potential to emit VOC of 0.32 tons per year. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Urea Granulation Unit (EU-008)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granulator (EU-008) shall be as follows:

- (1) The urea granulator (EU-008) shall be controlled by a wet scrubber at all times the process is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea granulator (EU-008) shall each not exceed 0.163 lb per ton granules, based on a three-hour average.

<b>BACT Analysis – Urea Granule Storage (EU-024)</b>
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#### **Emission Unit Description**

- (f) One (1) Urea Granule Storage Warehouse, identified as emission unit EU-024, approved for construction in 2014, particulate emissions are controlled by a baghouse, exhausting to stack S-024.

#### **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

#### **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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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:

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) 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.

(a) **Cyclones**

Cyclones are primarily used to control particulate matter (PM) with an aerodynamic diameter of 10 microns and greater. They are also used as pre-cleaners for other control devices and efficiently treat waste gas streams with high pollutant loadings. Emissions from the urea granule storage warehouse (EU-24) will contain significant amounts of fine particulate at a low grain loading. Therefore, a cyclone is not a technically feasible control device for this application.

(b) **Wet Scrubber**

Wet scrubbers are typically not used for fine particulate control due to the high liquid to gas ratios. They are more expensive to operate when compared to a baghouse and result in a waste liquid stream that may need special treatment. The wet scrubber can achieve collection efficiencies from 70% to 99% depending on the physical characteristics of the waste gas stream. The wet scrubber is a technically feasible control device for this application.

(c) **Electrostatic Precipitator**

Electrostatic precipitators are capable of removing particulate matter in the 2.5 micron range. Approximately 80% of all ESPs in the United States are used in the electric utility industry. This is not a common technology in the fertilizer production industry. This is due to the high capital and maintenance costs. Most modern ESPs can achieve collection efficiencies of 99% to 99.9%, while collection efficiencies of older units may be as low as 90%. Generally, ESPs are not competitive to baghouses for emission units with low pollutant loading and low gas flow rates. The ESP is not a technologically feasible control technology due to the operating characteristics of this waste gas stream.

(d) **Fabric Filters Dust Collectors (Baghouse)**

Baghouses have the capability to treat waste gas streams with particulate matter in the 2.5 micron range. Newer baghouse designs can achieve 99 to 99.9% control of particulate, while older units operate at 95% to 99.9% control. They are commonly used to control particulate emissions from the cement industry, coal cleaning, and quarry operations and are a technologically feasible control technology for the urea granule storage warehouse (EU-024).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the operation of the urea granule storage warehouse (EU-024):

- (a) Fabric Filter Dust Collectors (Baghouse) -- 95% to 99.9% control
- (b) Wet Scrubber -- 90% to 99.9%

The applicant has accepted a baghouse for control of the urea granule storage warehouse.



#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b>						
<b>Urea Granule Storage Warehouse (EU-024) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Urea Granule Storage Warehouse (EU-024)</b>	<b>1,587 ton urea/day</b>	<b>PM, PM<sub>10</sub>/PM<sub>2.5</sub> 0.17 lb/hr 3 hr average</b>	<b>Baghouse</b>
IA-0105	Iowa Fertilizer Company	10/26/12	Urea Granule Transfer	1,500 MT urea/day	PM - 0.005 gr/dscf PM <sub>10</sub> /PM <sub>2.5</sub> - 0.0013 gr/dscf, average 3 tests	Bin Vent Filter

#### **RBLC Review**

There is a single RBLC entry for controlling particulate matter emissions from urea granule storage warehouses. The Iowa Fertilizer Company (IFC) has the only granulated urea storage area listed in the RBLC. Particulate BACT IFC was based on an outlet grain loading of the baghouse controlling emissions. The baghouse was designed to control PM and PM<sub>10</sub> emissions to 0.005 gr/dscf. Midwest Fertilizer Corporation will control emissions to a lower level of 0.003 gr/dscf. The applicant will control PM<sub>2.5</sub> emissions to 0.003 gr/dscf. IFC proposed a lower emission rate of 0.0013 gr/scf for PM<sub>2.5</sub>. However, it is not clear that a baghouse collecting this material can routinely achieve a grain loading of 0.0013 gr/scf. Until tested and proven in practice, a grain loading of 0.003 gr/dscf represents the lowest level of PM<sub>2.5</sub> removal.

#### **Applicant Proposal**

The applicant has proposed the following for BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall not exceed 0.17 lb/hr, based on a three-hour average.

#### **Step 5: Select BACT**

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for the urea granule storage warehouse (EU-024):

- (a) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall not exceed 0.17 lb/hr, based on a three-hour average.

#### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The urea granule storage warehouse (EU-024) does not have the potential to emit NO<sub>x</sub>, CO, VOC, and GHG. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea granule storage warehouse (EU-024) for these pollutants and BACT analyses are not required.

**Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Urea Granule Storage Warehouse (EU-024)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the urea granule storage warehouse (EU-024) shall be as follows:

- (1) The urea granule storage warehouse (EU-024) shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the urea granule storage warehouse (EU-024) shall each not exceed 0.17 lb/hr, based on a three-hour average.

**BACT Analysis –Nitric Acid Plant (EU-009)**

**Emission Unit Description**

- (g) One (1) 1,840 metric ton per day Nitric Acid Plant, where production is based on 100% by weight acid equivalent solution, identified as emission unit EU-009, approved for construction in 2014, NO<sub>x</sub> and N<sub>2</sub>O are controlled by a catalytic reactor for N<sub>2</sub>O control and Selective Catalytic Reduction (SCR) for NO<sub>x</sub> control, identified as SCR-2, NO<sub>x</sub> CEMS, exhausting to stack S-009. [40 CFR 60, Subpart Ga]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit particulate. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the nitric acid plant (EU-009) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction
- (b) Non-Selective Catalytic Reduction (SNCR)
- (c) Selective Catalytic Reduction (SCR)

These add-on control technologies and combustion control approaches are discussed below.

- (a) **Selective Catalytic Reduction (SCR)**  
SCR is a system capable of reducing both NO<sub>x</sub> and N<sub>2</sub>O emissions from waste industrial gases. This is a feasible control technology for the nitric acid plant (EU-009).
- (b) **Non-Selective Catalytic Reduction (NSCR)**  
Nonselective catalytic reduction (NSCR) is an add-on NO<sub>x</sub> control technology for exhaust streams with low oxygen content. Nonselective catalytic reduction uses a catalyst reaction to reduce NO<sub>x</sub>, CO and hydrocarbons to water, carbon dioxide, and nitrogen. The system works by injecting a reducing agent into the exhaust stream prior to the catalytic reactor to reduce NO<sub>x</sub>. The control efficiency achieved ranges from 80% to 90%. Operating temperatures range from 700 F to 1,200 F and the oxygen concentration must be below 4%. This is a technologically feasible control technology for the nitric acid plant (EU-009).

(c) **Hydrogen Peroxide Injection**

Hydrogen peroxide injection was identified in the RBLC for the Kennewick Fertilizer Operation in the State of Washington. The project was granted an innovative control waiver under 40 CFR 52.21(v). After construction and operation, the BACT limit was reassessed to be 0.6 lb NO<sub>x</sub> / ton acid. This emission rate is greater than the emission limitation required by 40 CFR 60, Subpart Ga and no other facility is using this technology. This is not a feasible control technology for the nitric acid plant (EU-009).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the remaining control technologies in order of their NO<sub>x</sub> control efficiency and listed them below:

- (a) Selective Catalytic Reduction – 95% control
- (b) Non-Selective Catalytic Reduction (SNCR) – 93% control

The applicant has accepted top BACT.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Nitric Acid Plant (EU-009) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.064 lb/ton acid, 30 day average	SCR
T147-32322-00062	Ohio Valley Resources	09/25/13	Nitric Acid Units EU-001A EU-001B	630 tons/day, each	0.5 lb/ton nitric acid, 30 day average	SCR
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,905 MT/day	5 ppmv, 30 day rolling and 30 TPY, 12 month rolling	De-NO <sub>x</sub> System
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 7 Nitric Acid Plant	76,300 TPY Nitric Acid	0.524 lb/ton nitric acid; 27 ton/12 month rolling	SCR, 98% Control
WA-0318	Kennewick Fertilizer Operations	07/11/08	Plant 9 Nitric Acid Plant	270,000 TPY Nitric Acid	0.6 lb/ton acid, 400 lb/day, 47 ton/12 month rolling	Hydrogen Peroxide Injection, 98% Control

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Nitric Acid Plant (EU-009) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
GA-0109	PCS Nitrogen Fertilizer – Augusta Plant	05/10/05	Nitric Acid Plant	Unspecified	3 lb/ton 100% nitric acid 297 tons/yr	NSCR Combustor, 93% Control
OK-0135	Pryor Plant Chemical Company	02/23/09	Nitric Acid Plant #1	8.3 lb/hr	1.6 lb/ton annual, 3 lb/ton for a 7 day maximum, 58.2 TPY NO <sub>x</sub>	Extended Absorption with NSCR

#### **RBLC Review**

Nitric acid production units have been successfully controlled with SCR and NSCR. NO<sub>x</sub> emission rates from existing BACT determinations range from a high of 3.0 lb/ton to 0.5 lb/ton. The control efficiencies of the control technology are not directly comparable because the individual process designs result in a wide range of NO<sub>x</sub> generation rates. The best comparison is the emission rate per unit of production.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (b) NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.

The applicant has accepted top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the nitric acid plants (EU-009) as:

- (a) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (b) NO<sub>x</sub> emissions from the nitric acid stack shall not exceed 0.064 lb NO<sub>x</sub> per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, based on a 30-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.

### **CO PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit CO. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for CO and a BACT analysis is not required.

### **VOC PSD Applicability**

The nitric acid plant (EU-009) does not have the potential to emit VOC. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid plant (EU-009) for VOC and a BACT analysis is not required.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

The following GHG control technologies apply to the Nitric Acid Units (EU-001A and EU-001B):

- (1) Primary Controls – Suppression of  $N_2O$  formation
- (2) Secondary Controls – Reduction of  $N_2O$  after formation
- (3) Tertiary Controls – Reduction of  $N_2O$  using catalytic control
- (4) Plant Energy Efficiency Considerations

#### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Primary Controls – Suppression of  $N_2O$  formation**  
Primary controls refer to the modifications made to the catalyst and reaction conditions in the oxidation step to reduce the amount of  $N_2O$  formed. Types of primary controls include extension of the ammonia oxidation reactor. The extended reactor includes an extra chamber free of catalyst between the catalyst and the heat exchangers, allowing additional residence time. Additional primary controls include modification to the oxidation catalyst. The use of primary controls would be considered an inherently lower emitting design. The use of primary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (b) **Secondary Controls – Reduction of  $N_2O$  after formation**  
Secondary control refer to reductions in  $N_2O$  through the use of an additional catalyst, immediately after the oxidation step in the ammonia burner, in which  $N_2O$  is decomposed into nitrogen and oxygen. The use of secondary controls would be an add-on control technology. The use of secondary controls for greenhouse gas control for the nitric acid plant (EU-009) is technically feasible.
- (c) **Tertiary Controls – Reduction of  $N_2O$  using catalytic control**  
Tertiary controls refer to reduction in  $N_2O$  through catalytic reduction or decomposition after formation in the oxidation step. The catalyst can be placed either before or after the expander. The two types of catalyst used are non-selective catalytic reduction (NSCR) and catalytic conversion. The NSCR system converts  $N_2O$  with some sort of fuel over a catalyst to produce nitrogen and water. The catalytic conversion process does not require any added fuels or reagents to decompose  $N_2O$  to nitrogen and oxygen. There are several tertiary control systems capable of reducing both  $NO_x$  and  $N_2O$  from waste industrial gases. The Uhde EnviNOx System is one of these patented tertiary control systems. The use of tertiary controls would be capable of producing good results and is technically feasible.

(d) **Plant Energy Efficiency Considerations**

Plant energy efficiency considerations include process integration and heat recovery for steam production. The exothermic nature of the reactions means the nitric acid units are net exporters of energy. Therefore, careful consideration should be given to recovering as much of this thermal energy as possible to reduce the overall energy input to the plant. When energy inputs are reduced, greenhouse gas emissions are reduced. The use of plant energy efficiency considerations is a technically feasible control option for the Nitric Acid Units (EU-001A and EU-001B).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has reviewed the information submitted in support of this BACT determination and has ranked the remaining control options as shown below:

- (1) Tertiary Control (98% reduction, vendor guarantee)
- (2) Secondary Control (70% to 90% reduction)
- (3) Primary Control (30% to 85% reduction)
- (4) Plant Efficiency Considerations

A tertiary control system has been selected by the applicant. Therefore, no other analyses are required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Nitric Acid Plants (EU-009) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Nitric Acid Plant (EU-009)	1,840 MTD (2,028 ton acid/day)	0.613 lb N <sub>2</sub> O/ton acid, 3 hr avg., 100% by weight acid equivalent solution	Tertiary Controls
IA-0105	Iowa Fertilizer Company	10/26/12	Nitric Acid Plant	1,700 MT/day	N <sub>2</sub> O - 30 ppmv, avg. 3 tests; CO <sub>2e</sub> - 44,991 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests	N <sub>2</sub> O Uhde De-N <sub>2</sub> O System CO <sub>2e</sub> - 29,543 ton/12 month rolling; CH <sub>4</sub> - 40 ppmv, avg. 3 tests
T147-32322-00062	Ohio Valley Resources	09/25/13	Nitric Acid Plants (EU-001A/B)	630 tons per day, each	1.05 lb N <sub>2</sub> O per ton nitric acid, 3 hr. avg.	Tertiary Controls

### **RBLC Review**

The RBLC contains two entries for nitric acid units in the fertilizer industry. The Iowa Fertilizer Company and Ohio Valley Resources both use a proprietary control technology for  $N_2O$  control. These systems are designed to work with a paired nitric acid reactor. Midwest Fertilizer Corporation is using a tertiary control system using a catalytic reactor to control  $N_2O$  emissions from the Nitric Acid Plant. When all three nitric acid plants are compared on emissions calculated using 100% by weight nitric acid equivalent solution as the production variable, IFC will emit 0.7 lb  $N_2O$  per ton of 100% by weight nitric acid equivalent solution produced. MFC will emit 0.613 lb  $N_2O$  per ton of 100% by weight nitric acid equivalent solution produced. OVR will emit 1.05 lb  $N_2O$  per ton of 100% by weight nitric acid equivalent solution produced. The OVR permit limit applies at all times while the IFC and MFC limits exclude periods of startup, shutdown and malfunction. MFC has proposed the lowest  $N_2O$  emission rate in the RBLC.

### **Applicant Proposal**

The applicant proposed the use of a catalytic reactor to achieve a 95% reduction in  $N_2O$  at an emission rate of 0.613 lb  $N_2O$  per ton of nitric acid produced, with the production being expressed as 100 percent nitric acid, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature. This is top BACT. The applicant proposes the use of work practices to minimize startup, shutdown, and malfunction emissions.

The applicant provided information as part of the application indicating excess  $N_2O$  emissions during startup and shutdown events from the nitric acid plant are less than two (2) tons per year and IDEM considers these emissions negligible. As such, IDEM, OAQ concurs with the use of work practice standards during startup, shutdown and malfunction (SSM) events.

### **Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the nitric acid plant (EU-009) as:

- (a)  $N_2O$  emissions from the nitric acid plant (EU-009) shall be controlled at all times by a catalytic reactor, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and
- (b)  $N_2O$  emissions from the nitric acid plant (EU-009) shall not exceed 0.613 lb  $N_2O$  per ton of nitric acid, with the production being expressed as 100 percent nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (c) During periods of startup, shutdown, and malfunction,  $N_2O$  emissions shall be controlled by the use of good operational practices as described below:

#### **(1) Startup:**

Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and  $N_2O$  &  $NO_x$  reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric

acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for NO<sub>x</sub> reduction when the control equipment reaches an operating temperature of 600°F.

(2) **Shutdown:**

Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.

(3) **Malfunctions:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

IDEM, OAQ selected an emission limit based on N<sub>2</sub>O instead of CO<sub>2</sub>e because the only GHG reduced by the emission control system is N<sub>2</sub>O. The limit, therefore, requires a high level of performance in reducing the only GHG that can be controlled by the emission control system. N<sub>2</sub>O emissions comprise 95% of the pre-control CO<sub>2</sub>e emitted by the nitric acid stacks. The system does not reduce emissions of any other GHGs. CO<sub>2</sub> is present in nitric acid plant stack: it originates in the compressed air that is used as part of the nitric acid manufacturing process and a minor amount is generated when natural gas is used for N<sub>2</sub>O conversion.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Nitric Acid Plant (EU-009)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the nitric acid plant (EU-009) shall be as follows:

- (1) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall not exceed 0.064 lb NO<sub>x</sub> per ton nitric acid, with the production being expressed as 100 percent nitric acid, based on a thirty-day average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (2) NO<sub>x</sub> emissions from the nitric acid plant (EU-009) shall be controlled by a selective catalytic reduction system (SCR) at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature;
- (3) N<sub>2</sub>O emissions from the nitric acid plant (EU-009) shall be controlled by a catalytic reactor at all times the process is in operation, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature; and



- (4)  $\text{N}_2\text{O}$  emissions from the nitric acid plant (EU-009) shall not exceed 0.613 lb  $\text{N}_2\text{O}$  per ton of nitric acid, with the production being expressed as 100 percent nitric acid, based on a three-hour average, except during unit startup and shutdown when the catalyst temperature is below its operational minimum temperature.
- (5) During periods of startup, shutdown, and malfunction,  $\text{NO}_x$  and  $\text{N}_2\text{O}$  emissions shall be controlled by the use of good operational practices as described below:
  - (a) **Startup:**

Startup of the nitric acid plant from cold conditions begins with the introduction of liquid ammonia feed into the unit for nitric acid production and  $\text{N}_2\text{O}$  &  $\text{NO}_x$  reduction in the control equipment. The startup procedure takes approximately up to three (3) days. During plant startup, several individual processes and equipment begin operation including cooling water flow in the ammonia evaporator, steam flow into the ammonia preheater, air compressor, a series of tailgas heaters and condensers, an ammonia burner, a tailgas turbine, an absorption tower, and the control system. Ammonia oxidation in the ammonia burner does not commence until the temperature in the burner reaches 890 °C. The startup period ends when the ammonia burner reaches the required temperature, stable production of nitric acid is occurring in the absorption tower, and the control equipment reaches an operating temperature of 600 °F. During startup, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment as soon as operating temperatures are achieved. The control equipment shall begin operation and ammonia shall be injected for  $\text{NO}_x$  reduction when the control equipment reaches an operating temperature of 600°F.
  - (b) **Shutdown:**

Shutdown of the nitric acid plant from full load requires approximately up to two (2) days. During shutdown, BACT work practice standards shall consist of Good Combustion Practices, where applicable, and operation of the control equipment while the control equipment is above minimum operating temperature. The shutdown period begins when operating temperatures in the ammonia burner fall below 890°C and nitric acid production ceases after cutting of ammonia supplied to ammonia burner. The control equipment and ammonia injection will be discontinued when temperatures in the control equipment falls below 600°F.
  - (c) **Malfunctions:**

During malfunctions, BACT work practice standards shall be followed for the emission unit and its air pollution control equipment as stated in Condition B.13, Emergency Conditions.

<b>BACT Analysis – Natural Gas Combustion Turbines (EU-013A and EU-013B)</b>
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**Emission Unit Description**

- (h) Two (2) natural gas-fired, open-simple cycle combustion turbines with heat recovery, identified as EU-013A and EU-013B, approved for construction in 2014, each with a maximum heat input capacity of 283 MMBtu/hr, with low NO<sub>x</sub> burners, emissions are uncontrolled exhausting to stacks S-013A and S-013B, respectively.  
[40 CFR 60, Subpart KKKK]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Add-On Controls;
- (b) Fuel Specifications; and
- (c) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

- (a) **Add-on Controls**  
Add-on controls for particulate control from low sulfur natural gas-fired open-simple cycle combustion turbines with heat recovery includes wet scrubbers, fabric filter baghouse, electrostatic precipitator, and cyclones. None of these technologies is feasible for the combustion turbines because the particulate loading is already below the removal capabilities of these control devices. Therefore, add-on controls are not a feasible control strategy for the natural gas-fired combustion turbines.
- (b) **Fuel Specifications**  
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate matter emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such, fuel specifications are the primary method of particulate matter control and are a feasible control technology for the combustion turbines.
- (c) **Good Combustion Practices**  
Good combustion practices as well as operation and maintenance of the combustion turbines to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices and combustion controls are a technically feasible control option for the open-simple cycle combustion turbines with heat recovery (EU-013A/B).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control options. Therefore a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Open-Simple Cycle Combustion Turbines (EU-013A/B) – PM, PM <sub>10</sub> and PM <sub>2.5</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	Each Unit 283 MMBtu/hr 22.5 MW	PM 0.0019 lb/MMBtu, 3 hr avg.  PM <sub>10</sub> and PM <sub>2.5</sub> 0.0076 lb/MMBtu, 3 hr avg.	Natural Gas and Good Combustion Practices
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	Each Unit 80 MW	PM 10.8 lb/hr	Unknown
WY-0070	Black Hills Power, Inc.	08/27/12	Two Natural Gas Combined Cycle Turbines	Each Unit 40 MW	PM 4.0 lb/hr 3-hr avg. and 17.5 ton each calendar year	Good Combustion Practices
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	Each Unit 30 MW	PM <sub>10</sub> 2.11 lb/hr, maximum and 8.5 TPY maximum	Natural Gas and Good Combustion
VA-0319	Gateway Green Energy	05/02/13	Two Combined Cycle Combustion Turbines	Each Unit 80 MW	PM <sub>10</sub> and PM <sub>2.5</sub> 5.0 lb/hr 3-hr avg.	Good Combustion Practices, clean burning fuel
LA-0256	Westlake Vinyls Company	04/03/12	Three Cogeneration Combustion Turbines	Each Unit 50 MW	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 3.72 lb/hr, maximum	Natural Gas and Good Combustion Practice
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two 35 MW Gas Turbines with HRSG	Each Unit 35 MW	PM <sub>10</sub> 10.03 lb/hr 71.32 TPY	Natural Gas and Combustion Control

### **RBLC Review**

None of the RBLC entries proposed add-on controls for particulate matter. In all cases, good combustion practices was used to limit particulate matter emissions. Emissions from combustion turbines can vary significantly depending on the operating points selected to establish the BACT limit. This variation explains the difference in emission rates for similar units. The applicant has proposed the lowest emission level presented in the RBLC.

### **Applicant Proposal**

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery shall be controlled by the use of good combustion practices and proper design at all times the units are in operation;
- (b) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (c) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.0019 lb/MMBtu; and
- (d) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery shall be controlled by the use of good combustion practices and proper design at all times the units are in operation;
- (b) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (c) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average; and
- (d) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Good Combustion Practices;
- (b) Fuel Specification;
- (c) Selective Catalytic Reduction (SCR); and
- (d) Catalytic Oxidation.

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Good Combustion Practices**

NO<sub>x</sub> is one of the primary pollutants created by natural gas combustion in an open-simple cycle combustion turbine. In addition, emissions from combustion turbines are highly dependent on the operating load on the turbine. Turbines are designed to achieve maximum efficiency at peak load and controlling emissions over all loads levels is extremely difficult.

NO<sub>x</sub> is a mixture of NO and NO<sub>2</sub> in a variable composition, that is formed by three mechanisms. Thermal NO<sub>x</sub> occurs by the fixation of atmospheric oxygen and nitrogen, which occurs at high combustion temperatures. A second method of NO<sub>x</sub> formation is prompt NO<sub>x</sub>. Prompt NO<sub>x</sub> forms from early combustion reaction of nitrogen and hydrocarbon radicals from the fuel. The final method of NO<sub>x</sub> formation is fuel-bound NO<sub>x</sub>. Fuel-bound NO<sub>x</sub> can occur when the fuel contains significant amounts of nitrogen. Natural gas has negligible amounts of nitrogen. Of the three methods, the most prevalent method of NO<sub>x</sub> formation is thermal NO<sub>x</sub>. Thermal NO<sub>x</sub> is controlled in a combustion turbine by maintaining a constant fuel-to-air ratio that maintains the flame temperature below the stoichiometric adiabatic temperature. Most new combustion turbines use lean pre-mixed combustion systems referred to as dry low NO<sub>x</sub> combustion that operates in a tightly controlled fuel-to-air mixture that results in a modest peak flame temperature. Good operational practices are a feasible control technology for the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B).

### **(b) Fuel Specification**

Selection of a fuel with negligible amounts of nitrogen will reduce fuel-bound NO<sub>x</sub> and will result in modest reductions in NO<sub>x</sub> emissions. Selection of a clean burning fossil fuel such as natural gas will minimize fuel-bound NO<sub>x</sub>. Fuel specification is a feasible control technology for the natural gas-fired combustion turbines.

### **(c) Selective Catalytic Reduction (SCR)**

The primary post-combustion NO<sub>x</sub> control method in use today is selective catalytic reduction (SCR). SCR units inject ammonia into the flue gas and reacts with NO<sub>x</sub> in the presence of a catalyst to produce nitrogen and water vapor. The ammonia is normally injected in the heat recovery steam generator where the temperature of the exhaust generally matches the activation temperature of the catalyst. Low temperature installations are available with operating temperatures in the 300 °F to 400 °F range. High temperature systems are available in 800 °F to 1,100 °F range. 80% to 90% reductions in NO<sub>x</sub> are typical with SCR systems.

SCR systems are expensive and can significantly impact the feasibility of a project using smaller gas turbines. SCR units are also subject to ammonia "slip," where unreacted ammonia escapes the process and create nuisance problems. Selective Catalytic Reduction (SCR) is a feasible control option for the combustion turbines.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the control effectiveness of all remaining control technologies:

- (a) Selective Catalytic Reduction (SCR) – 80% to 90% control
- (b) Good Combustion Practices – less than 80% control
- (c) Fuel Specification – minimal reduction

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Open-Simple Cycle Combustion Turbines (EU-013A/B) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW	2 ppmvd @ 15% O <sub>2</sub> 1 hr avg.	SCR
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW, each	2 ppmvd @15%, 24-hr rolling	SCR
WY-0061	Black Hills Corporation – Neil Simpson Two	05/10/04	Combined Cycle Combustion Turbine	40 MW	2.5 ppmv @ 15%, 24-hr rolling 4.7 lb/hr	Dry Low NO <sub>x</sub> Combustors and SCR
DE-0023	NRG Energy Center Dover	06/05/13	Gas Turbine with HRSG	One 655 MMBtu/hr (70 MW)	5.76 lb/hr 1 hr avg.; 2.5 ppm@15% O <sub>2</sub> 1 hr avg.	SCR
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	3 ppmv @15% O <sub>2</sub> , 1 hr avg., 4.6 lb/hr, 30 day rolling, 25.5 TPY	SCR
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	80 MW	3 ppmv @15%, 24-hr avg.	Low NO <sub>x</sub> Combustors and SCR
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two Gas Turbines with HRSG and duct burners	35 MW, 312 MMBtu/hr, each	11.43 lb/hr, 3 hr avg.; 90.77 TPY	Low NO <sub>x</sub> Combustors and SCR
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	Each Unit 283 MMBtu/hr 22.5 MW	22.65 ppm <sub>vd</sub> at 15% oxygen, 3 hr avg., > 50% load	Dry Low NO <sub>x</sub> Combustors, Good Combustion Practices
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	30 MW 290 MMBtu/hr each unit	25 ppm <sub>d</sub> @ 15%, > 50% load	Dry Low NO <sub>x</sub> Combustor

### **RBLC Review**

The vast majority of entries for NO<sub>x</sub> control in the RBLC are for units over 180 MW. These units are typically installed by electric utilities and NO<sub>x</sub> is controlled by SCR and dry low NO<sub>x</sub> combustors. In addition, not all of the units operate in an open-simple cycle mode. The applicant proposes the installation of dry low NO<sub>x</sub> combustors. The emission rates of the individual units listed in the RBLC must be reviewed carefully because NO<sub>x</sub> emissions can vary significantly depending on the load point selected to set the emission rate. The very lowest emission rate is 2.5 ppm<sub>v</sub> for a 70 MW unit and 25 ppm<sub>v</sub> for a 30 MW unit. The proposed MFC units are 22.5 MW, each. BACT limits for NO<sub>x</sub> generally increase as the size of the combustion turbine decreases. The applicant proposed a NO<sub>x</sub> BACT limit which is similar to the Sabine Pass LNG Terminal, which is the closest unit in size to that proposed by Midwest Fertilizer Corporation. SCR is typically installed on units in the 25 to 800 MW range. The units proposed by Midwest Fertilizer Corporation are 22.5 MW, each.

### **Applicant Proposal**

The applicant proposed BACT as:

- (a) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices and the use of dry low NO<sub>x</sub> combustors.
- (b) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.

The applicant provided an economic analysis of the use of SCR on the open-simple cycle combustion turbines with heat recovery to demonstrate to IDEM, OAQ that the use of SCR is not economically feasible on these units. A summary of the analysis is shown below:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
SCR	103.43 tons per year	93.09 tons per year (90% reduction)	\$7,489,200	\$1,451,490	\$2,154,500	\$23,145	Ammonia Emissions, Additional Electrical Required
Capital Recovery Factor = 0.09439 ( 7% for a 20 year life cycle)							

The economic analysis indicates the level of NO<sub>x</sub> reduction does not justify the addition of selective catalytic reduction. In addition, the applicant has proposed an emission rate below a previously issued BACT for the turbine closest to its size. The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices and the use of dry low NO<sub>x</sub> combustors.
- (b) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Fuel Specifications
- (b) Good Combustion Practices
- (c) Oxidation Catalyst

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluates all identified control methods below:

- (a) **Fuel Specifications**  
Selection of a low carbon fuel will reduce the amount of carbon available for the conversion to CO. Therefore, fuel specifications are a feasible CO control option for the combustion turbines.
- (b) **Good Combustion Practices**  
CO emissions result from incomplete combustion when there is insufficient residence time at high temperature. As with NO<sub>x</sub>, CO emissions vary as the operating load of the turbine varies. Also, the methods used to reduce NO<sub>x</sub> will increase CO emissions. Proper management of the combustion process will result in a reduction in CO. Therefore, good combustion practices is a feasible control option.
- (c) **Oxidation Catalyst**  
The primary CO control method used in combustion turbines is catalytic oxidation. In fact, some SCR units incorporate CO oxidation modules to reduce CO and NO<sub>x</sub> simultaneously. CO catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. CO catalysts on gas turbines can achieve up to 90% reduction in CO emissions. Therefore, catalytic oxidation is a technically feasible control option of the open-simple cycle combustion turbines with heat recovery.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ ranked all feasible control technologies below:

- (a) Oxidation Catalyst – up to 90% control
- (b) Good Combustion Practices – less than 90% control
- (c) Fuel specifications – minimal reduction

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Open-Simple Cycle Combustion Turbines (EU-013A/B) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW	2 ppmv @ 15% 3 hr avg.	Ox Catalyst SCR
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	4 ppmv @15%, 1 hr avg. 3.7 lb/hr, 30 day rolling, 32 TPY	Ox Catalyst
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	Each Unit 283 MMBtu/hr 22.5 MW	0.03 lb/MMBtu, 3 hr avg., > 50% peak load	Good Combustion Practices
NE-0017	Beatrice Power Station	08/03/04	Two Combustion Turbines with HRSG	80 MW	18.4 lb/hr, 30 day rolling	Good Combustion and Cat Oxidation
DE-0023	NRG Energy Center Dover	06/05/13	Gas Turbine with HRSG	One 655 MMBtu/hr (70 MW)	0.032 lb/MMBtu 1 hr avg. 19.54 lb/hr, 1 hr avg.	Ox Catalyst 0.3 lb/MW-hr
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW each unit	17.5 ppmv@15% 1 hr rolling avg.	Good Combustion
WY-0061	Black Hills Corporation – Neil Simpson Two	05/10/04	Combined Cycle Combustion Turbine	40 MW	37.2 ppmv @ 15%, 1 hr avg., 43.8 lb/hr, 1 hr avg.	Good Combustion

#### RBLC Review

The RBLC indicates the use of catalytic oxidation and good combustion practices are the methods used to control CO emissions in natural gas-fired combustion turbines. The applicant is proposing an emission rate of 0.03 lb/MMBtu. The lowest entries are from the Vernon City Light and Power turbine and the Black Hills Power turbine. These units are significantly larger units and use oxidation catalyst to control CO. The proposed emission rate is below the most recent BACT entry from the NRG Energy Center in Delaware. The NRG Energy Center turbine is also significantly larger and uses an oxidation catalyst.

### Applicant Proposal

The applicant proposed the following for BACT:

- (a) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average; and
- (b) CO emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by proper design, and good combustion practices.

The following economic analysis is presented to display the cost effectiveness of catalytic oxidation for control of CO:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
Catalytic Oxidation	37.19 TPY	27.89 TPY (75% Control)	\$46,097,520	\$4,846,593	\$5,992,677 + \$4,846,593 = \$10,839,270	\$388,644	Additional emissions due to makeup fuel to heat exhaust to catalyst activation temperature.
Capital Recovery Factor = 0.13 ( 5% for a 10 year life cycle)							

The economic analysis presented by the applicant shows catalytic oxidation is not a cost effective control option for small natural gas-fired combustion turbines.

### Step 5: Select BACT

IDEM, OAQ has established CO BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average; and
- (b) CO emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by proper design, and good combustion practices.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Good Combustion Practices
- (b) Oxidation Catalyst

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluates all identified control methods below:

- (a) **Good Combustion Practices**  
VOC emissions in gas combustion turbines result from incomplete combustion. These VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for the gas combustion turbines.
- (b) **Oxidation Catalyst**  
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reduction of 85% to 90%. The use of an oxidation catalyst is a feasible control technology for the combustion turbines.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ ranks all feasible control methods below:

- (a) Oxidation Catalyst – 85% to 90% control
- (b) Good Combustion Practices – less than 85% control

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Open-Simple Cycle Combustion Turbines (EU-013A/B) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
CA-1096	Vernon City Light and Power	12/05/05	Combined Cycle Combustion Turbine	43 MW Combined Cycle Turbine	2 ppmv @ 15%, 1 hr avg.	Ox Catalyst SCR
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	<u>Each Unit</u> 283 MMBtu/hr 22.5 MW	2.5 ppm <sub>vd</sub> @ 15% 1 hr avg.	Good Combustion Practices
TX-0548	Madison Bell Energy Center	11/06/09	Four Combined Cycle Combustion Turbines	75 MW, each	2.5 ppmv @ 15%, 1 hr rolling	Good Combustion
LA-0194	Sabine Pass LNG Terminal	09/03/09	Four Gas Turbine Generators	30 MW, 290 MMBtu/hr, each	1.2 lb/hr, maximum 4.84 TPY, maximum	Nat Gas and Good Combustion
WY-0070	Black Hills Power, Inc.	08/27/12	Combined Cycle Combustion Turbine	40 MW	3 ppmv @ 15%, 1 hr avg. 3 lb/hr, 3hr avg. 14.7 TPY	Ox Catalyst
DE-0023	NRG Energy Center Dover	06/05/13	Combined Cycle Combustion Turbines	One 655 MMBtu/hr (70 MW)	6.4 lb/hr, 1 hr avg.	Ox Catalyst
TX-0497	Ineos Chocolate Bayou Facility	10/02/07	Two Gas Turbines with HRSG	35 MW, each	6.14 lb/hr 40.88 TPY	Combustion Control

#### RBLC Review

VOC control methods listed in the RBLC include good combustion practices and the use of an oxidation catalyst. Existing RBLC entries indicate VOC emission rates range from a low of 2 ppm<sub>vd</sub> to well over 8 ppm<sub>vd</sub>. The applicant proposed an emission rate of 2.5 ppm<sub>vd</sub>. The proposed rate is the lowest level of control for any unit in the RBLC except for the Vernon City facility, which is a combined cycle plant and is significantly larger than the MFC facility. The Vernon City facility uses an oxidation catalyst to achieve the 2 ppm<sub>vd</sub> emission rate.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub>, based on a one-hour average.

- (b) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices; and
- (c) Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas.

The applicant provided the following cost effectiveness analysis:

Control Alternative	Captured Emissions	Emission Reduction	Capital Cost (\$)	Operating Costs (\$/year)	Total Annualized Costs (\$/year)	Cost Effectiveness (\$/ton)	Other Impacts
Catalytic Oxidation	8.68 TPY	1.74 TPY (20% Control)	\$46,097,520	\$4,846,593	\$5,992,677 + \$4,846,593 = \$10,839,270	\$6,229,465	Additional emissions due to makeup fuel to heat exhaust to catalyst activation temperature.
Capital Recovery Factor = 0.13 ( 5% for a 10 year life cycle)							

#### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the open-simple cycle combustion turbines with heat recovery (EU-013A/B) as:

- (a) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average.
- (b) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by the use of proper design, good combustion practices; and
- (c) Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas.

#### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies or operational procedures for use in the open-simple cycle combustion turbines with heat recovery (EU-013A/B):

- (a) Fuel Specifications;
- (b) Good Combustion Practices; and
- (c) Carbon Capture and Sequestration (CCS).

## **Step 2: Eliminate Technically Infeasible Options**

### **(a) Fuel Specifications**

Greenhouse gas emissions from the natural gas-fired combustion turbines are directly related to the carbon content of the fuel and the efficiency of the combustion process. Natural gas contains approximately 34 pounds of carbon per million Btu. Fuel oil contains approximately 48 pounds of carbon per million Btu. Ash free coal contains 66 pounds of carbon per million Btu. Therefore, the selection of a low carbon fuel such as natural gas will reduce greenhouse gas emissions. Fuel specifications are a feasible control technology for greenhouse gas emissions.

### **(b) Good Combustion Practices**

Greenhouse gas emissions from the natural gas-fired combustion turbines are directly related to the carbon content of the fuel and the efficiency of the combustion process. Management of the combustion process will result in more complete combustion which reduces methane emitted from the turbines. Because more complete combustion can reduce methane emissions, good combustion practices are a feasible control technology for the natural gas combustion turbines.

### **(c) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. It was determined that CCS is not available to Midwest Fertilizer Corporation. Therefore, it is not a feasible control option.

## **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control technologies. Therefore, no ranking is necessary.

## **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b>						
<b>Open-Simple Cycle Combustion Turbines (EU-013A/B) – Greenhouse Gases (GHG)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
VA-0319	Gateway Green Energy	05/02/13	Two Combustion Turbines	80 MW, each	CO <sub>2</sub> e 1,050 lb/MW-hr, 12 month avg.  295,961 TPY	Natural gas, high efficiency design, max heat rate of 8,983 Btu/kW-h
DE-0023	NRG Energy Center Dover	06/05/13	Two Combined Cycle Combustion Turbines	One 655 MMBtu/hr (70 MW)	CO <sub>2</sub> e 1,085 lb/MW-hr, 12 month rolling avg.	None

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Open-Simple Cycle Combustion Turbines (EU-013A/B) – Greenhouse Gases (GHG)						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0256	Westlake Vinyls Company	04/03/12	Three Cogeneration Turbines	50 MW 475 MMBtu/hr, each unit	$CO_2e$ 55,576.77 lb/hr, maximum 243,426.26 TPY	Natural Gas and Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Two Natural Gas Open-Simple Cycle Combustion Turbines with HRSG (EU-013A/B)	<u>Each Unit</u> 283 MMBtu/hr 22.5 MW	$CO_2$ 144,890 ton/12 month rolling 116.89 lb/MMBtu, 3 hr avg., 12,666 Btu/kw-hr	Good Engineering Design and Combustion Practices, Nat Gas

#### RBLC Review

The RBLC includes three greenhouse gas BACT determinations. Emission controls included the use of a low carbon fuel, good engineering design and good combustion practices. As with the other pollutants, emission rates of greenhouse gases increases as the electrical capacity of the generator increases. The unit closest to the Midwest Fertilizer Corporation is the Westlake Vinyls Company cogeneration turbines. GHG BACT for this unit was selected to match the emission rate corresponding to the emission factor listed in 40 CFR 98. Midwest Fertilizer Corporation, in a like manner, proposed the use of the emission factor from 40 CFR 98, along with a thermal efficiency.

#### Applicant Proposal

The applicant proposed the following for BACT:

- Each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall combust natural gas;
- Greenhouse gas emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by proper design and good combustion practices;
- Thermal efficiency of each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- $CO_2$  emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons  $CO_2$  per twelve consecutive month period with compliance determined at the end of each month; and
- $CO_2$  emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 116.89 lb/MMBtu, based on a three-hour average.

#### Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the open-simple cycle combustion turbines (EU-013A/B) as:

- The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- Greenhouse gas emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall be controlled by proper design and good combustion practices;

- (c) Thermal efficiency of each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (d) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and
- (e) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Open-Simple Cycle Combustion Turbines (EU-013A/B)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the open-simple cycle combustion turbines (EU-013A/B) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of proper design and good combustion practices at all times the units are in operation;
- (2) The natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall combust natural gas;
- (3) PM emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0019 lb/MMBtu, based on a three-hour average;
- (4) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall each not exceed 0.0076 lb/MMBtu, based on a three-hour average;
- (5) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall be controlled by the use of dry low NO<sub>x</sub> combustors;
- (6) NO<sub>x</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 22.65 ppm<sub>vd</sub> at 15% oxygen and greater than 50% peak load, based on a three-hour average.
- (7) CO emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not exceed 0.03 lb/MMBtu and greater than 50% peak load, based on a three-hour average;
- (8) VOC emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 2.5 ppm<sub>vd</sub> at 15% oxygen, based on a one-hour average;



- (9) Thermal efficiency of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) shall not be less than 12,666 Btu/kw-hr;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired open-simple cycle combustion turbines with heat recovery (EU-013A/B) emissions shall not exceed 116.89 lb/MMBtu, based on a three-hour average; and
- (11) CO<sub>2</sub> emissions from each open-simple cycle combustion turbine with heat recovery (EU-013A/B) shall not exceed 144,890 tons CO<sub>2</sub> per twelve consecutive month period with compliance determined at the end of each month.

<b>BACT Analysis – Natural Gas Auxiliary Boilers (EU-012A/B/C)</b>
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**Emission Unit Description**

- (i) Three (3) natural gas-fired auxiliary boilers, identified as emission units EU-012A, EU-012B, and EU-012C, approved for construction in 2014, each with a maximum rated heat input capacity of 218.6 MMBtu/hr, NO<sub>x</sub> emissions are controlled by low NO<sub>x</sub> burners and Flue Gas Recirculation (FGR), NO<sub>x</sub> CEMS, exhausting to stacks, S-012A, S-012B, and S-012C, respectively. [40 CFR 60, Subpart Db]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (PM<sub>2.5</sub>) 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.

**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) **Cyclones**  
As discussed under the particulate matter BACT for the reformer furnace, the concentration of PM, PM<sub>10</sub> and PM<sub>2.5</sub> are extremely low for natural gas combustion. IDEM, OAQ expects no more than 0.005 grains/cubic foot. This low level of pollutant loading is already well below the normal removal efficiency of a cyclone. Therefore, a cyclone is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).
- (b) **Wet Scrubbers**  
Typical loadings for wet scrubbers range from 0.1 to 50 grains per cubic foot of exhaust gas. The concentration of PM, PM<sub>10</sub> and PM<sub>2.5</sub> are extremely low for natural gas combustion. IDEM, OAQ expects a loading of no more than 0.005 grains/cubic foot. This low level of pollutant loading is already well below the normal removal efficiency of a wet scrubber. Therefore, a wet scrubber is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).
- (c) **Electrostatic Precipitators**  
An electrostatic precipitator is a control device that uses electrical forces to collect charged particles on collector plates. This control device is typically used to control particulate loading in the 0.5 to 50 grains per cubic foot range. As with the cyclone and wet scrubber, the emission rate from natural gas combustion is well below the typical loading of an electrostatic precipitator. Therefore, the electrostatic precipitator is not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).
- (d) **Fabric Filter Dust Collectors (Baghouse)**  
A typical baghouse design outlet concentration is 0.005 grains per cubic foot. Since the result of combustion of this source is already at the typical design outlet loading of the baghouse, fabric filters are not a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).
- (e) **Fuel Specification – Clean Burning Fuel**  
Clean burning fuels, such as natural gas, have a very low potential to generate particulate emissions. Fuel specifications are a feasible particulate control technology for the auxiliary boilers (EU-012A/B/C).
- (f) **Good Combustion Practices**  
Good combustion practices as well as operation and maintenance of the boiler to keep it in good working order per the manufacturer's specifications will minimize PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions. Good combustion practices are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been identified for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the auxiliary boilers (EU-012A/B/C):

- (a) Fuel Specification – Clean Burning Fuel
- (b) Good Combustion Practices

Both control methods have been selected by the applicant for implementation on the auxiliary boilers. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Auxiliary Boilers (EU-012A/B/C) – PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0024 lb/MMBtu, avg, 3 tests; 1.06 ton/12 month rolling	Good Combustion Practices
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr Each	PM – 1.9 lb/MMCF PM <sub>10</sub> – 7.6 lb/MMCF PM <sub>2.5</sub> – 7.6 lb/MMCF, 3 hr avg., 1,501.91 MMCF/12 month rolling	Good Combustion Practices, Proper Design, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to D	218 MMBtu/hr, Each	PM – 1.9 lb/MMCF PM <sub>10</sub> – 7.6 lb/MMCF PM <sub>2.5</sub> – 7.6 lb/MMCF, 3 hr avg., 2,800 MMCF/12 month rolling over 4 units	Good Combustion Practices, Proper Design, natural gas
LA-0231	Lake Charles Cogeneration	06/22/09	Auxiliary Boiler	938.3 MMBtu/hr	6.99 lb PM <sub>10</sub> /hr, filterable and condensable, max.	Good Design and Operation
OH-0307	Biomass Energy South Point	04/04/06	Auxiliary Boiler	247 MMBtu/hr	0.0070 lb/MMBtu, 1.73 lb/hr, 3.26 ton/year	None
TX-0371	Corpus Christi Energy Center	02/04/00	Auxiliary Boilers 1 to 3	315 MMBtu/hr	0.005 lb/MMBtu, filterable, 1.57 lb/hr, maximum	None
NC-0101	Forsyth Energy Plant	09/29/05	Auxiliary Boiler	110.20 MMBtu/hr	0.82 lb/hr, PM <sub>10</sub> filterable, 3 hr avg., 0.0070 lb/MMBtu	Good Combustion, Low Sulfur Fuel
PA-0187	Gray's Ferry Cogen Partnership	03/21/01	Auxiliary Boiler	1,119 MMBtu/hr	PM/PM <sub>10</sub> -0.005 lb/MMBtu, filterable, 34.4 lb/hr	Good Combustion Practices

### **RBLC Review**

PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from all of the auxiliary boilers in the RBLC are controlled by good combustion practices. Particulate emissions from natural gas-fired combustion sources are already extremely low and add-on controls are not practical. The emission limits for the Corpus Christi Energy Center and Gray's Ferry Cogeneration Partnership appear to be lower emission rates; however, the emission rates shown only include filterable particulate matter. Once condensable particulate matter is included, the emission rates are identical to the applicant's proposal. The particulate matter limits for an auxiliary boiler at the Iowa Fertilizer Company were the lowest emission rates found.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (c) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;
- (d) Natural gas usage in each natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (e) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation.

The applicant's proposal is consistent with a majority of the entries in the RBLC for PM, PM<sub>10</sub> and PM<sub>2.5</sub>. The proposed emission limits of 1.9 and 7.6 lb/MMCF are the default emission factors for natural gas combustion found in AP-42 for PM and PM<sub>10</sub>, PM<sub>2.5</sub>, respectively. A permit for the Iowa Fertilizer Company (IFC) was recently issued by the Iowa Department of Natural Resources (IDNR) at an emission rate of 0.0024 lb/MMBtu. The IFC permit limit is lower than the limit proposed by the applicant. IDNR established this limit based on two stack tests at a single boiler. IDEM, OAQ believes the emission rate proposed by the applicant is appropriate for BACT based on the following factors:

- (a) Add-on emission controls have been demonstrated to be infeasible or not cost-effective.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility -- a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

**Step 5: Select BACT**

IDEM, OAQ has established the following as BACT for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> for the auxiliary boilers (EU-012A/B/C):

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (c) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;
- (d) Natural gas usage in each natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month; and
- (e) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

NO<sub>x</sub> emissions from the auxiliary boilers (EU-012A/B/C) can be controlled with the following control technologies:

- (a) Selective Catalytic Reduction (SCR);
- (b) Selective Non-Catalytic Reduction (SNCR);
- (c) Low NO<sub>x</sub> Burner (LNB);
- (d) Flue Gas Recirculation (FGR);
- (e) Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR); and
- (f) Good Combustion Practices.

**Step 2: Eliminate Technically Infeasible Options**

All NO<sub>x</sub> control strategies are discussed below:

- (a) **Selective Catalytic Reduction (SCR)**  
Selective catalytic reduction (SCR) is typically installed on stable steady state processes. The efficiency of NO<sub>x</sub> control will be reduced for processes that are not stable, require frequent changes in the mode of operation, or are installed on units with short operating times. This is due to the fact that SCR operation is dependent on the operating temperature of the process. SCR is effective in a narrow temperature range of 500 °F to 1,100 °F. The natural gas-fired auxiliary boilers will each operate up to 7,008 hours per year. While this is not continuous operation, it is stable enough for effective operation of an SCR control device. SCR is a feasible control technology for NO<sub>x</sub>.

- (b) **Selective Non-Catalytic Reduction (SNCR)**  
SNCR is similar to SCR, except it is operated without a catalyst bed. This control technology is well suited to exhaust gases that would foul a catalyst bed. SNCR does require a higher operating temperature for the reduction of NO<sub>x</sub> to occur. The reaction must occur between 1,600 °F and 2,000 °F. The reaction temperature is significantly higher than the exhaust temperature of the auxiliary boilers. This would require heating of the exhaust gas to at least 1,600 °F. The additional heating would result in an increase of most of the other regulated pollutants. SNCR is not a technologically feasible control option for the auxiliary boilers due to the energy requirements to heat the exhaust gas.
- (c) **Low NO<sub>x</sub> Burner (LNB)**  
Low NO<sub>x</sub> burners can reduce the formation of NO<sub>x</sub> through the careful control of the air-fuel mixture during combustion. Low NO<sub>x</sub> burners are more of a design feature than a control device. This technology is widely used on boilers and is a feasible control option for the auxiliary boilers.
- (d) **Flue Gas Recirculation (FGR)**  
Flue gas recirculation can reduce NO<sub>x</sub> emissions by recirculating a portion of the flue gas to lower the flame temperature during combustion. Like low NO<sub>x</sub> burners, it is a design feature more than a control device. FGR is widely used on boilers and is a feasible control option for the auxiliary boilers.
- (e) **Low NO<sub>x</sub> Burner (LNB) with Flue Gas Recirculation (FGR)**  
Low NO<sub>x</sub> burners and FGR can be used in conjunction to achieve higher overall emission reductions. The combination of the control devices is a feasible control option for the auxiliary boilers.
- (f) **Good Combustion Practices**  
Good combustion practices as well as operation and maintenance of the boiler to keep it in good working order per the manufacturer's specifications will minimize NO<sub>x</sub> emissions. Good combustion practices are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control technologies for NO<sub>x</sub> control are ranked below:

- (a) Selective Catalytic Reduction – up to 90% control
- (b) Low NO<sub>x</sub> burners with Flue Gas Recirculation – up to 90% control
- (c) Low NO<sub>x</sub> Burners – up to 50% control
- (d) Flue Gas Recirculation – up to 25% control
- (e) Good Combustion Practices – less than 25% control

Typically the combination of low NO<sub>x</sub> burners and flue gas recirculation are capable of achieving 55% to 60% control. The applicant is proposing installation of LNB and FGR to achieve the same level of reduction as SCR. This would represent top BACT.

To estimate 90% NO<sub>x</sub> emission reduction, IDEM used the uncontrolled NO<sub>x</sub> emission factor from AP-42, Chapter 1.4, Table 1.4-1 SCC 1-02-006-01 of 190 lb NO<sub>x</sub> / MMCF (0.19 lb/MMBtu). If the practical limit of NO<sub>x</sub> removal were 90%, a boiler would be expected to achieve a NO<sub>x</sub> emission rate of 0.019 lb/MMBtu. The Iowa Fertilizer Corporation proposed a NO<sub>x</sub> emission rate of 0.0125 lb/MMBtu, which represents a 93.4% reduction. This level of reduction exceeds a level IDEM considers practical and achievable at all times over the life of the unit. MFC proposed an emission rate of 0.02 lb/MMBtu or an 89.5% reduction. MFC will achieve the lowest NO<sub>x</sub> emission rate for an auxiliary boiler listed in the RBLC that has been demonstrated in practice. This is top BACT.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b> <b>Auxiliary Boilers (EU-012A/B/C) – NO<sub>x</sub> BACT</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Co	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0125 lb/MMBtu, 30 day avg., 5.52 ton/12 month rolling	Low NO <sub>x</sub> Burner, FGR
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr	20.40 lb/MMCF, 3 hr average, 1,501.91 MMCF/12 month rolling	Low NO <sub>x</sub> Burners, FGR, Good Combustion Practices, Proper Design, Natural Gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Boilers EU-011A to EU-011D	218 MMBtu/hr Each	20.40 lb/MMCF, 24 hr avg., 2,802 MMCF/12 month rolling, over 4 boilers	Ultra Low NO <sub>x</sub> Burner, FGR
NJ-0043	Liberty Gen. Station	03/28/02	Auxiliary Boiler	200 MMBtu/hr	0.036 lb/MMBtu, 7.2 lb/hr, max.	SCR
CO-0052	Rocky Mountain Energy Ctr.	08/11/02	Natural Gas Fired Boiler (Aux. Boiler)	129 MMBtu/hr	0.038 lb/MMBtu 1,900 hr/yr	Low NO <sub>x</sub> Burner
TX-0386	Amella Energy Ctr.	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu, 6.2 lb/hr	None
TX-0411	Amella Energy Ctr.	03/26/02	Auxiliary Boiler	155 MMBtu/hr	0.04 lb/MMBtu	None

**RBLC Review**

A review of similar units in the RBLC indicates selective catalytic reduction, low NO<sub>x</sub> burners, flue gas recirculation are the principle NO<sub>x</sub> control strategies installed on auxiliary boilers. The lowest emission rate listed in the RBLC is 0.0125 lb/MMBtu for the Iowa facility. The Iowa units have not been constructed and this limit has not been demonstrated in practice. The next lowest limit is 20.4 lb/MMCF for the Ohio Valley Resources facility and it is the same as the emission rate proposed by the applicant.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (a) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (b) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of proper design and good combustion practices at all times the boilers are in operation;
- (c) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (d) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average; and
- (e) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant has proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the auxiliary boilers (EU-012/A/B/C) as:

- (a) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (b) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of proper design and good combustion practices at all times the boilers are in operation;
- (c) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (d) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average; and
- (e) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **CO BACT**

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following CO control technologies for the auxiliary boilers:

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.



### **Step 2: Eliminate Technically Infeasible Options**

Each of the control technologies identified in Step 1 are discussed below:

(a) **Thermal Oxidation**

This control technology is typically used to control organic vapors. Theoretically, it is a control technology for CO. During combustion, CO is formed by the incomplete combustion of hydrocarbons. The additional thermal energy forces a more complete oxidation of the fuel resulting in the production of lower CO levels and higher carbon dioxide and water vapor levels. While theoretically possible, it normally is not feasible because of the low heating value of natural gas combustion products. Significant supplemental fuel will be required to heat the exhaust gas to the required operating temperature to achieve destruction. The boiler exhaust gas is at 350 °F and would require heating to at least 1,500 °F to achieve any reduction. In practice, thermal oxidation has not been installed on natural gas combustion sources. Thermal oxidation is not a feasible control technology for the auxiliary boilers.

(b) **Catalytic Oxidation**

Catalytic oxidation is a process similar to thermal oxidation. Catalytic oxidation uses a catalyst to allow the oxidation process to occur at a lower temperature. The exhaust gas would only be heated to 600 °F to 800 °F. Carbon Monoxide in the exhaust gas is combined with additional oxygen to form carbon dioxide and water vapor. As with thermal oxidation, it is not traditionally installed on natural gas combustion sources because of the low heating value of the exhaust gas. The combustion of additional fuel to raise the stack gas temperature will result in an increase in other regulated pollutants.

(c) **Flares**

Flares are another form of thermal oxidation. Theoretically, carbon monoxide is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in carbon monoxide. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 1,100 °F will result in an increase in other regulated pollutants. While technologically feasible, it is not a feasible control option for the auxiliary boilers.

(d) **Combustion Control**

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 CO emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

There is only one technically feasible control technology for carbon monoxide control in the auxiliary boilers. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Auxiliary Boilers (EU-012A/B/C) – CO BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0013 lb/MMBtu, avg. 3 runs; 0.57 ton/12 month rolling	Good Combustion Practices
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr	37.22 lb/MMCF, 3 hr avg.; 1,501.91 MMCF/12 month rolling, each	Good Combustion Practices, Design, Natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	4 Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr Each	37.22 lb/MMCF, 3 hr avg., each 2,802 MMCF/12 month rolling, total	Good Combustion Practices, Design, Natural gas
CA-1212	City of Palmdale Hybrid Power	12/20/12	Auxiliary Boiler	110 MMBtu/hr	50 ppmvd @ 3% O <sub>2</sub> , 3 hr average	None
MI-0389	Consumers Energy	12/29/09	Auxiliary Boiler	220 MMBtu/hr	0.0350 lb/MMBtu, test method	Efficient Combustion
GA-0127	Southern Company	01/07/08	Auxiliary Boilers	200 MMBtu/hr	0.0370 lb/MMBtu, 3 hr average	None
OH-0310	American Municipal Power	10/08/09	Auxiliary Boiler	150 MMBtu/hr	12.6 lb/hr, 5.52 ton/12 month rolling; 400 ppmvd @ 3%, 3 hr avg.	None

#### RBLC Review

A review of similar emission units in the RBLC indicates add-on controls are not typically employed on natural gas combustion sources. If a control method is specified, it is good combustion practices. All of the RBLC entries used the AP-42 emission factor for open combustion of natural gas, except for Iowa Fertilizer Corporation (IFC) and American Municipal Power. American Municipal Power used a higher emission rate. The IFC boiler used a much lower emission rate.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) CO emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (c) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

The applicant's proposal is consistent with the majority of RBLC entries for CO control on auxiliary boilers. IDEM, OAQ does not believe the IFC emission rate reflects BACT for CO control on natural gas combustion units because:

- (a) Add-on emission controls have been demonstrated to be infeasible.
- (b) The majority of the entries in the RBLC for uncontrolled natural gas-fired combustion units are derived from the AP-42 emission factors, which are based on stack tests on a large sample size of natural gas-burning facilities.
- (c) The emission limits in the IFC permit set by IDNR are based on two stack tests at the same facility -- a 429 MMBtu/hr auxiliary boiler located at the Walter Scott Generating Plant in Council Bluffs, Iowa. These test results do not establish BACT.
  - (1) Two stack test results at the same facility are not representative of the emission rate achievable at a large range of natural gas facility types and sizes. The AP-42 emission factor for natural gas combustion is a better reflection of what is achievable for an uncontrolled natural gas unit.
  - (2) IFC's facilities have not yet begun operations, and consequently the achievability of the IFC BACT limits have not been demonstrated in practice.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the natural gas fired auxiliary boilers (EU-012A/B/C) as:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) CO emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (c) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for control of carbon monoxide in the natural gas-fired auxiliary boilers (EU-012A/B/C):

- (a) Thermal Oxidation;
- (b) Catalytic Oxidation;
- (c) Flares; and
- (d) Combustion Control.

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ has evaluated all identified control technologies listed above:

- (a) **Thermal Oxidation**  
This control technology is typically used to control organic vapors. It is most effective in controlling emissions with high organic loading. The organic containing gas stream is mixed with additional fuel to oxidize the organic components to carbon dioxide and water vapor. The additional thermal energy forces a more complete oxidation of the fuel resulting in lower VOC levels and higher carbon dioxide emission levels. Catalytic Oxidation is not normally used on natural gas combustion products because of their low heating value. Significant supplemental fuel will be required to heat the exhaust gas to the required operating temperature to achieve destruction. The boiler exhaust gas is at 350 °F and would require heating to at least 1,500 °F to achieve any reduction. In practice, thermal oxidation has not been installed on natural gas combustion sources. Thermal oxidation is not a feasible control technology for the auxiliary boilers.
- (b) **Catalytic Oxidation**  
Catalytic oxidation is a process similar to thermal oxidation. Catalytic oxidation uses a catalyst to allow the oxidation process to occur at a lower temperature. The exhaust gas would only be heated to 600 °F to 800 °F. VOC in the exhaust gas is combined with additional oxygen to form carbon dioxide and water vapor. As with thermal oxidation, it is not traditionally installed on natural gas combustion sources because of the low heating value of the exhaust gas. The combustion of additional fuel to raise the stack gas temperature will result in an increase in other regulated pollutants. Catalytic oxidation is not a feasible control technology for the auxiliary boilers.
- (c) **Flares**  
Flares are another form of thermal oxidation. The VOC containing exhaust gas is combined with additional fuel to raise the exhaust gas temperature to a level where it is converted to carbon dioxide and water vapor. As with the thermal oxidizer, flares are not typically installed on natural gas combustion sources to achieve a reduction in volatile organic compounds. The combustion of additional fuel to raise the temperature of the exhaust gas to at least 600 °F will result in an increase in other regulated pollutants. VOC control by flare is not a feasible control option for the auxiliary boilers.
- (d) **Combustion Control**  
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 VOC emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has proposed the only feasible control technology for the auxiliary boilers. Therefore, a ranking is not necessary.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Auxiliary Boilers (EU-012A/B/C) – VOC BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	0.0014 lb/MMBtu, 3 run avg., 0.62 ton/12 month rolling	Good Combustion Practices
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr	5.5 lb/MMCF, 3 hr avg.; 1,501.91 MMCF/12 month rolling	Good Combustion, Design, natural gas
T 147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr Each	5.5 lb/MMCF, 3 hr avg.; 2,802 MMCF/12 month rolling, total	Combustion Practices, Design, Natural Gas
WV-0023	Longview Power, X	02/03/09	Auxiliary Natural Gas Boiler	225 MMBtu/hr	0.0054 lb/MMBtu, 3 hr rolling; 3,000 hr/yr	Use Natural Gas, Good Combustion Practices
OH-0310	American Municipal Power Generating	10/08/09	Auxiliary Natural Gas Boiler	150 MMBtu/hr	5.5 lb/MMCF 0.83 lb/hr 0.36 ton/12 month rolling	None
NJ-0043	Liberty Generating Station	03/28/02	Auxiliary Natural Gas Boiler	200 MMBtu/hr	50 ppmvd, 7% O <sub>2</sub> 1.6 lb/hr, 0.008 lb/MMBtu	CO Catalyst
TX-0386	Amella Energy Center	08/26/04	Auxiliary Natural Gas Boiler	155 MMBtu/hr	3.1 lb/hr, maximum	None

### **RBLC Review**

A review of BACT determinations in the RBLC indicates add-on control technology is not typically used on natural gas-fired boilers. VOC emissions are exclusively controlled by good combustion practices and the use of a low carbon fuel, natural gas. The lowest emission rate achieved is at the Iowa Fertilizer Corporation (IFC) with the use of good combustion practices.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) VOC emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **Step 5: Select BACT**

IDEM, OAQ has established the following as VOC BACT for the auxiliary boilers:

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) VOC emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average; and
- (d) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

- (a) Carbon Capture and Sequestration (CCS);
- (b) Energy Efficient Design and Good Combustion Practices; and
- (c) Low Carbon Fuel.

#### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated each of the identified control options below:

- (a) **Carbon Capture and Sequestration (CCS)**  
CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. IDEM, OAQ evaluated the capture and sequestration of all sources of greenhouse gases in the greenhouse gas BACT analysis for the reformer furnace. It was determined that CCS was not a feasible control option for the entire source because the technology is not available or applicable to Midwest Fertilizer Corporation.

(b) **Energy Efficient Design and Good Combustion Practices**

Good combustion practices and energy efficient design as well as operation and maintenance of the auxiliary boilers to keep them in good working order per the manufacturer's specifications will minimize GHG emissions. Good combustion practices and combustion controls are a technically feasible control option for the auxiliary boilers (EU-012A/B/C).

(c) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of low carbon fuels such as natural gas is a technically feasible control option for the auxiliary boilers.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted all feasible control options. Therefore, no ranking is necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Auxiliary Boilers (EU-012A/B/C) – GHG BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Auxiliary Boilers (EU-012A/B/C)	218.6 MMBtu/hr	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. 1,501.91 MMCF/12 month rolling	Natural gas, Good Combustion/Design, 80% Efficiency (HHV)
T 147-32322-00062	Ohio Valley Resources	09/25/13	Auxiliary Boilers EU-011A to EU-011D	218 MMBtu/hr each	CO <sub>2</sub> – 59.61 ton/MMCF, 3 hr avg. 2,802 MMCF/12 month rolling	Good Combustion Practices/Design, 80% efficiency, Natural gas
IA-0105	Iowa Fertilizer Company	10/26/12	Startup Heater	110.12 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, avg. 3 tests; CH <sub>4</sub> – 0.0023 lb/MMBtu, avg. 3 tests; N <sub>2</sub> O – 0.0006 lb/MMBtu, avg. 3 tests CO <sub>2e</sub> – 638 ton/12 month rolling	Good Combustion Practices

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Auxiliary Boilers (EU-012A/B/C) – GHG BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Auxiliary Boiler	472.4 MMBtu/hr	CO <sub>2</sub> – 117 lb/MMBtu, 30 day rolling; CH <sub>4</sub> – 0.0023 lb/MMBtu, 3 run avg.; N <sub>2</sub> O – 0.0006 lb/MMBtu, 3 run avg. CO <sub>2</sub> e –51,748 ton/12 month rolling.	Good Combustion Practices
T147-30464-00060	Indiana Gasification	06/27/12	Auxiliary Boiler	172 MMBtu/hr	88,167 tons CO <sub>2</sub> /12 month rolling	81% Thermal Efficiency, Use Natural Gas, Efficient Design

#### RBLC Review

A review of the RBLC indicates greenhouse gas emissions are controlled by good combustion practices and design features to maximize the efficiency of the boiler. Efficient boilers will require less fuel which reduces greenhouse gas emissions. All of the entries use 117 lb/MMBtu for CO<sub>2</sub> emissions. This is equivalent to 59.61 ton CO<sub>2</sub>/MMCF.

#### Applicant Proposal

The applicant has proposed the following for BACT:

- The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- Greenhouse gas emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency; and
- Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

The applicant has accepted top BACT.



**Step 5: Select BACT**

- (a) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (b) Greenhouse gas emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and the use of good combustion practices at all times the boilers are in operation;
- (c) Natural gas usage in each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (d) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- (e) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
- (f) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other greenhouse gases (GHGs), such as methane and N<sub>2</sub>O 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Auxiliary Boilers (EU-012A/B/C)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be as follows:

- (1) The natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall combust natural gas;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC, and GHG emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by proper design and good combustion practices at all times the boilers are in operation;
- (3) Natural gas usage in each natural gas-fired auxiliary boiler (EU-012A, EU-012B and EU-012C) shall not exceed 1,501.91 MMCF per twelve consecutive month period with compliance determined at the end of each month;
- (4) PM emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 1.9 lb/MMCF, based on a three-hour average;
- (5) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall each not exceed 7.6 lb/MMCF, based on a three-hour average;

- (6) NO<sub>x</sub> emissions from the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be controlled by the use of low NO<sub>x</sub> burners and flue gas recirculation at all times boilers are in operation;
- (7) NO<sub>x</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 20.40 lb/MMCF, based on a three-hour average;
- (8) CO emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 37.22 lb/MMCF, based on a three-hour average;
- (9) VOC emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 5.5 lb/MMCF, based on a three-hour average;
- (10) CO<sub>2</sub> emissions from each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall not exceed 59.61 ton/MMCF of natural gas combusted, based on a three-hour average;
- (11) Each of the natural gas-fired auxiliary boilers (EU-012A, EU-012B and EU-012C) shall be designed to achieve a minimum 80% thermal efficiency (HHV); and
- (12) Each of the boilers (EU-012A, EU-012B, and EU-012C) shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery.

<b>BACT Analysis – Fugitive Emissions from Equipment Leaks (F-1)</b>
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**Emission Unit Description**

- (j) Fugitive emissions from equipment leaks, identified as emission unit F-1.  
[40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> PSD Applicability**

Fugitive emissions from equipment leaks do not have a potential to emit particulate. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for PM, PM<sub>10</sub> and PM<sub>2.5</sub> and a BACT analysis is not required for these pollutants.

**NO<sub>x</sub> PSD Applicability**

Fugitive emissions from equipment leaks have the potential to emit NO<sub>x</sub> of 0.01 ton per year. IDEM, OAQ considers NO<sub>x</sub> emissions from these units as insignificant and has determined that it would be technically infeasible and not cost effective to require NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

**CO PSD Applicability**

Fugitive emissions from equipment leaks do not have a potential to emit carbon monoxide. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for CO and a BACT analysis is not required for this pollutant.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following control technologies for VOC control from fugitive emission sources:

- (a) Leak Detection and Repair Program (LDAR)
- (b) No Control Option

### **Step 2: Eliminate Technically Infeasible Options**

- (a) **Leak Detection and Repair Program (LDAR)**  
A leak detection and control program (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fitting, sampling connections, etc. LDAR is a work practice that assists sources identify leaking equipment so that emissions can be reduced through systematic repair or replacement. The key to the effectiveness of fugitive emission control is the regularly scheduled inspections and a defined repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC emissions.
- (b) **No Control Option**  
It is possible that fugitive emissions from a source are so small that the time and cost required to establish and implement an LDAR program are not cost effective. Fugitive VOC emissions were estimated by the source at 14.39 tons per year. The use of no control is a technically feasible control option for the fugitive VOC emissions.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

- (a) LDAR (98% control)
- (b) No Control (0% control)

The applicant proposed an LDAR program which is top BACT. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Fugitive Emissions (F-1) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Fugitive Emissions (F-1)	NA	None	LDAR Program 40 CFR 60, Subpart VVa
T147-32322-00062	Ohio Valley Resources	09/25/13	Process Fugitive VOC	NA	None	LDAR Program 40 CFR 60, Subpart VVa
LA-0245	Valero, Hydrogen Plant	12/15/10	Fugitives FUG0030	NA	23.74 TPY	LDAR that meets LA Refinery MACT
TX-0575	Sabina Petrochemicals	08/20/10	ALKFUG, BDEFUG, UTILFUG	NA	9.01 TPY	LEAR Leak Detection and Repair Program 98% Control
FL-0318	Highlands Ethanol Facility	12/10/09	Fugitive VOC Equipment Leaks	NA	19.6 TPY	LDAR Program 40 CFR 60, Subpart VVa
LA-0197	Alliance Refinery	07/21/09	Unit Fugitives	NA	13.22 lb/hr 57.89 TPY	LDAR that meets LA Refinery MACT
FL-0322	Southeast Renewable Fuels	12/23/10	Fugitive VOC Emissions	NA	6.52 TPY	LDAR Program 40 CFR 60.4821a through 60.482-10a or 60.480a(e)

#### RBLC Review

A review of the RBLC for similar emission sources indicates fugitive VOC emissions are controlled exclusively by an LDAR program.

#### Applicant Proposal

The applicant has proposed the following for BACT:

- (a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program.

#### Step 5: Select BACT

IDEM, OAQ has established the following as VOC BACT for fugitive VOC emissions:

- (a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

## Greenhouse Gas BACT

### **Step 1: Identify Potential Control Technologies**

The only potential control technology or operational practice to control fugitive greenhouse gas emissions is a leak detection and repair program.

### **Step 2: Eliminate Technically Infeasible Options**

The source estimates fugitive greenhouse gas emissions of 1,215 tons as CO<sub>2</sub>e will be emitted. The applicant estimates there will be small amounts of fugitive GHG emissions from equipment leaks, compressor leaks, valve and connector leaks, etc. These fugitive emissions are small in the overall operation of the facility but must be addressed. An LDAR program is technically feasible for the fugitive GHG emissions from this source.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

There is only one control option; therefore, a ranking or further analysis is not needed.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Fugitive Emissions (F-1) – Greenhouse Gases						
RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
FL-0330	Port Dolphin Energy	12/01/11	Fugitive GHG Emissions	NA	No Numerical Limits	Gas Leak Detection System
LA-0257	Sabine Pass LNG Terminal	12/06/11	Fugitive GHG Emissions	NA	89,629 TPY CO <sub>2</sub> e, maximum	LDAR Program
LA-0263	Phillips 66, Alliance Refinery	07/25/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, Monitor Total Hydrocarbon Instead of VOC
T147-30464-00060	Indiana Gasification	06/27/12	Fugitive GHG Emissions	NA	No Numerical Limits	LDAR, visual/audio inspection of compressors
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Fugitive GHG Emissions (F-1)</b>	<b>NA</b>	<b>None</b>	<b>None</b>
T 147-32322-00062	Ohio Valley Resources	09/25/13	Fugitive GHG Emissions	NA	None	None

### **RBLC Review**

The RBLC has limited entries for fugitive greenhouse gas emissions. The only control method listed for fugitive GHG control was the use of a leak detection and repair program (LDAR). Fugitive GHG emissions of the Ohio Valley Resources facility were so small, no control option was selected.

### Applicant Proposal

The applicant proposed the no control option.

### Step 5: Select BACT

IDEM, OAQ believes the greenhouse gas emissions from fugitive sources are insignificant. No additional BACT requirements will be imposed.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for Fugitive Emissions (F-1)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for fugitive emissions (F-1) shall be as follows:

- (1) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart VVa shall serve as BACT for VOC fugitive emissions.

<b>BACT Analysis – Truck Loading Operation (EU-020)</b>
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#### Emission Unit Description

- (k) One (1) 3,000 metric ton per day Truck Loading Operation for dry product, identified as EU-020, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-20, exhausting to stack S-020.

#### PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT

##### Step 1: Identify Potential Control Technologies

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses).

##### Step 2: Eliminate Technically Infeasible Options

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

- (a) **Cyclones**  
Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the truck loading operation because it is ineffective in control of fine particulate matter.
- (b) **Wet Scrubber**  
A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may

require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the truck loadout operation.

(c) **Electrostatic Precipitator (ESP)**

An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the truck loading operation because of the intermittent operation of the emission unit and its cost.

(d) **Fabric Filter Dust Collector**

Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the truck loading operation.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

(a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control

(b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the truck loading operation. This is top BACT. No additional analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b> <b>Truck Loading Operation (EU-020) – PM, PM<sub>10</sub>, and PM<sub>2.5</sub></b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Truck Loading Operation (EU-020)	3,080 tons granulated Urea per day	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.12 lb/hr, 3 hr average	Baghouse
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

#### **RBLC Review**

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and have higher emission rates than the applicant's proposal.

#### **Applicant Proposal**

The applicant has proposed the following for BACT:

- (a) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall not exceed 0.12 lb/hr, based on a three-hour average.

#### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the truck loadout operation identified as EU-020 as follows:

- (a) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.

#### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The truck loading operation (EU-020) does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the truck loading operation for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Truck Loadout Operation (EU-020)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the truck loadout operation (EU-020) shall be as follows:

- (1) The truck loading operation identified as EU-020 shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the truck loading operation identified as EU-020 shall each not exceed 0.12 lb/hr, based on a three-hour average.

<b>BACT Analysis – Rail Loading Operation (EU-021A)</b>
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#### **Emission Unit Description**

- (i) One (1) 3,000 metric ton per day Rail Loading Operation for dry product, identified as EU-021A, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21A, exhausting to stack S-21A.



## **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP);
- (d) Fabric Filter Dust Collectors (Baghouses)

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

- (a) **Cyclones**  
Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the rail loading operation because it is ineffective in control of fine particulate matter.
- (b) **Wet Scrubber**  
A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the rail loading operation.
- (c) **Electrostatic Precipitator (ESP)**  
An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the rail loading operation because of the intermittent operation of the emission unit and its cost.
- (d) **Fabric Filter Dust Collector**  
Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the rail loading operation.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

- (a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control
- (b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the rail loading operation. This is top BACT. No additional analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Rail Loading Operation (EU-021A) – PM, PM <sub>10</sub> , and PM <sub>2.5</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Rail Loading Operation (EU-021A)	3,080 ton urea per day	PM, PM <sub>10</sub> , PM <sub>2.5</sub> – 0.21 lb/hr, 3 hr avg.	Baghouse
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

**RBLC Review**

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and have higher emission rates than the applicant's proposal.

**Applicant Proposal**

The applicant has proposed the following for BACT:

- The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall not exceed 0.21 lb/hr, based on a three-hour average.

**Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the rail loadout operation identified as EU-021A as follows:

- (a) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.

**NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The rail loading operation (EU-021A) does not have NO<sub>x</sub>, CO, VOC, or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the rail loading operation for these pollutants and BACT analyses are not required for these pollutants.

**Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT)  
Summary Analysis for the Rail Loading Operation (EU-021A)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for rail loading operation (EU-021A) shall be as follows:

- (1) The rail loading operation identified as EU-021A shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the rail loading operation identified as EU-021A shall each not exceed 0.21 lb/hr, based on a three-hour average.

**BACT Analysis – Urea Junction Operation (EU-021B)**

**Insignificant Activity**

- (m) One (1) 3,000 metric ton per day Urea Junction Operation for dry product, identified as EU-021B, approved for construction in 2014, particulate emissions are controlled by a fabric filter dust collector, identified as BH-21B, exhausting to stack S-021B.

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

- (a) Cyclones;
- (b) Wet Scrubbers;
- (c) Electrostatic Precipitators (ESP); and
- (d) Fabric Filter Dust Collectors (Baghouses).

### **Step 2: Eliminate Technically Infeasible Options**

IDEM, OAQ evaluated all potential control technologies identified in Step 1 below:

(a) **Cyclones**

Cyclones are typically used to pretreat an exhaust stream before another particulate control device and are most effective at collection of larger particle diameters. The U.S. EPA Air Pollution Control Technology Fact Sheet for Cyclones indicate a control efficiency of 0% to 40% can be anticipated for PM<sub>2.5</sub>. A cyclone can achieve 70% to 90% control of PM. Granulated urea used as a fertilizer has granule diameters in the 1.0 to 2.8 millimeter range and emissions from loadout will contain significant amounts of PM<sub>2.5</sub>. A cyclone is not a feasible control technology for the urea junction operation because it is ineffective in control of fine particulate matter.

(b) **Wet Scrubber**

A wet scrubber can be used to collect fine and/or soluble particulate or as a mist eliminator to collect aerosols including VOC and sulfuric acid mist. It is susceptible to clogging if significant amount of fine material is present in the exhaust stream. It will require more maintenance, energy input, and will generate significant amounts of waste water that may require treatment. This technology can achieve 70% to 99% control of fine particulate matter. This is a feasible control technology for the urea junction operation.

(c) **Electrostatic Precipitator (ESP)**

An electrostatic precipitator is capable of fine particulate matter removal. However, ESPs generally have high capital, maintenance, and energy requirements. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. The truck loading operation will generate particulate emission on an infrequent basis. Emissions are created when the dry material is loaded into the trucks. An ESP is not a feasible control option for the urea junction operation because of the intermittent operation of the emission unit.

(d) **Fabric Filter Dust Collector**

Fabric filter dust collectors are used widely for control of fine particulate matter. They are capable of high collection efficiencies and are a feasible control technology for the urea junction operation.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

IDEM, OAQ has ranked the feasible control technologies by control effectiveness:

- (a) Fabric Filter Dust Collectors (Baghouses) at 99% to 99.9% control
- (b) Wet Scrubbers at 70% to 99% control

The applicant has accepted a fabric filter dust collector to control emissions from the rail loading operation. This is top BACT. No additional analysis is required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Urea Junction Operation (EU-021B) – PM, PM <sub>10</sub> , and PM <sub>2.5</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Urea Junction Operation (EU-021B)	3,080 tons urea per day	PM, PM <sub>10</sub> , PM <sub>2.5</sub> – 0.21 lb/hr, 3 hour average	Baghouse
IA-0106	CF Industries Nitrogen	07/12/13	Urea Loading	10,000 tons urea per day	PM – 0.003 lb/ton, avg. 3 tests, 5.48 ton/12 month rolling; PM <sub>10</sub> – 0.0011 lb/ton, 3 test runs, 2.01 ton/12 month rolling; PM <sub>2.5</sub> – 0.0011 lb/ton, 3 test avg., 1.97 ton/12 month rolling	Bin Vent Filter
IA-0105	Iowa Fertilizer Company	10/26/12	Granulated Urea Transfer	1,500 metric tons per day	PM – 0.005 lb/ton, avg. 3 runs; PM <sub>10</sub> – 0.005 lb/ton, avg. 3 runs; PM <sub>2.5</sub> – 0.0013 lb/ton, avg. 3 runs	Bin Vent Filter

#### RBLC Review

There are only two entries in the RBLC for granulated urea transfer or unloading. They both are from Iowa and similar emission rates to the applicant's proposal.

#### Applicant Proposal

The applicant has proposed the following for BACT:

- The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

#### Step 5: Select BACT

IDEM, OAAQ has established PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT for the urea junction operation identified as EU-021B as follows:

- The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The urea junction operation (EU-021B) does not have NO<sub>x</sub>, CO, VOC, or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea junction operation for these pollutants and a BACT analyses are not required for these pollutants.

#### **Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Urea Junction Operation (EU-021B)**

Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for urea junction operation (EU-021B) shall be as follows:

- (1) The urea junction operation identified as EU-021B shall be controlled by a baghouse at all times the emission unit is in operation; and
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the urea junction operation identified as EU-021B shall each not exceed 0.21 lb/hr, based on a three-hour average.

#### **BACT Analysis – Ammonia Storage Flare (EU-016)**

##### **Insignificant Activity**

- (n) One (1) 1.5 MMBtu/hr ammonia storage flare, using a natural gas-fired pilot, identified as emission unit EU-016, approved for construction in 2014, used to control ammonia emissions from the storage tanks, exhausting to stack S-016. [326 IAC 2-2]

##### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

###### **Step 1: Identify Potential Control Technologies**

In evaluating BACT for flare PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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 good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare gas recovery.

Add-on PM, PM<sub>10</sub> and PM<sub>2.5</sub> controls that may be used on other types of sources, such as cyclones, baghouses, ESPs, or scrubbers are not utilized on flares.

###### **Step 2: Eliminate Technically Infeasible Options**

Each option listed above is evaluated as follows:

- (a) **Flare design and good combustion practices**  
Flare design and operation are key elements in the emissions performance of flares. The ammonia storage flare (EU-016) 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 use of flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).

(b) **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<sub>10</sub> and PM<sub>2.5</sub> will be less. The use of process flaring minimizing practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The remaining technically feasible control technologies for flares are:

- (1) Proper flare design and good combustion practices; and
- (2) Process flaring minimization practices.

Both controls listed above are proposed to be implemented by the source; therefore, no ranking of control technologies is needed.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Ammonia Storage Flare (EU-016) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	PM - 0.0019 lb/MMBtu PM <sub>10/2.5</sub> - 0.0075 lb/MMBtu, 3 hr avg. both	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	PM - 0.0019 lb/MMBtu PM <sub>10/2.5</sub> - 0.0075 lb/MMBtu, 3 hr avg. both	Good combustion practice/flare design, flare minimization plan, natural gas

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Storage Flare (EU-016) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.40 MMBtu/hr	None	Work Practice, Good Combustion Practices

#### RBLC Review

A review of the PM/PM<sub>10</sub>/PM<sub>2.5</sub> control strategies from the RBLC indicates no add-on controls are used. The most recent entry indicates PM, PM<sub>10</sub> and PM<sub>2.5</sub> are normally controlled by work practice standards, good design and good combustion practices. IDEM, OAQ believes the lowest emission rate from a natural gas-fired flare is 1.9 lb/MMCF for PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub>, using the AP-42 emission factor, Chapter 1.4. There are additional entries for natural gas flares in the RBLC; however, these entries are for flares using landfill gas or are flares in continuous use. This flare normally does not control emissions. It is used during process venting operations that occur during process upsets, startups and shut downs.

#### Applicant Proposal

The applicant proposed:

- (a) Proper flare design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices.

The applicant's proposal is consistent with the RBLC entries shown in the table above for emergency flares that are not in continuous service. IDEM, OAQ is adding limits for PM, PM<sub>10</sub> and PM<sub>2.5</sub> based on the standard emission rates in AP-42, Chapter 1.4 of 1.9 lb/MMCF of PM and 7.6 lb/MMCF for PM<sub>10</sub> and PM<sub>2.5</sub> and a heating value of 1,020 MMBtu/MMCF.

#### Step 5: Select BACT

IDEM has established the following as BACT for PM, PM<sub>10</sub> and PM<sub>2.5</sub> for ammonia storage flare (EU-016):

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and



- (3) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (c) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (e) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.

#### **NO<sub>x</sub> BACT**

##### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of NO<sub>x</sub> in the ammonia storage flare (EU-016):

- (1) Flare design and good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare Gas Recovery.

Certain NO<sub>x</sub> 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**

- (a) **Flare design and good combustion practices**  
Flare design and good combustion practices – flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices are technically feasible control options for the ammonia storage flare (EU-016).
- (b) **Process flaring minimization practices**  
Process flaring minimization practices – to the extent actions can be taken to minimize the volume of gas going to the flare, emissions of NO<sub>x</sub> will be less. The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for NO<sub>x</sub>. Therefore, no ranking or further analysis is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) -- NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	0.068 lb/MMBtu, 3 hr avg. pilot and 125.00 lb/hr venting, 168 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.068 lb/MMBtu, pilot 3 hr avg., and 125.00 lb/hr venting, 168 hr venting/12 month rolling	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson	08/20/12	Combustion Flares	35 MMCF/yr	0.068 lb/MMBtu	None
TX-0436	Borger Carbon Black	10/03/02	Dryers, Boilers, Flare	Unspecified	0.1 lb/MMBtu	Good Combustion Practices and Design
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion 40 CFR 60.18
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numeric Limit	Work Practice, Good Combustion Practices

#### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The lowest emission rate achievable does not vary significantly for similar flares in similar service. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

#### **Applicant Proposal**

The applicant proposes the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas;
- (c) The use of flare minimization practices; and
- (d) The NO<sub>x</sub> emission rate from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu for the pilot and purge gas.

The applicant proposed top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ has established NO<sub>x</sub> BACT for the ammonia storage flare (EU-016) as:

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
- (c) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (d) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and

- (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (e) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (f) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

The following control technologies have been identified for the control of CO in the ammonia storage flare (EU-016):

- (1) Flare design and good combustion practices;
- (2) Process flaring minimization practices; and
- (3) Flare Gas Recovery.

Certain CO controls that may be used on other types of sources, such as thermal or catalytic oxidation 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**

(a) **Flare design and good combustion practices**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).

(b) **Process flaring minimization practices**

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.

The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.

- (2) Another difference is that the Midwest Fertilizer Corporation facility flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant proposed both proper flare design and operation along with flare minimization practices as BACT for CO. Therefore, no ranking is required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	0.37 lb/MMBtu, 3 hr average	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.37 lb/MMBtu 3 hr average	Good combustion practice/flare design, flare minimization plan, natural gas
AK-0076	Exxon, Point Thomson Production	08/20/12	Combustion Flares	35 MMCF/yr	0.37 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Work Practice, Good Combustion
ID-0017	Southeast Idaho Energy	02/10/09	Process Flare SRC21	1.5 MMBtu/hr pilot	No emissions from the process, no limit on pilot emissions	Good Combustion 40 CFR 60.18

### **RBLC Review**

The requirements of BACT listed in the RBLC for flares mostly involve the proper design and operation of the flare to achieve a manufacturer performance guarantee. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a reoccurrence.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) CO emissions from the ammonia storage flare (EU-016) shall be controlled by good combustion practices;
- (b) CO emissions from the ammonia storage flare (EU-016) shall be controlled by the use of flare minimization practices (FMP); and
- (c) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu.

The applicant proposed top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the ammonia storage flare (EU-016) as:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (2) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by the use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.

## VOC BACT

### **Step 1: Identify Potential Control Technologies**

The following VOC control technologies are available to the ammonia storage flare (EU-016):

- (1) Flare Design and Monitoring;
- (2) Process Flaring Minimization Practices; and
- (3) Flare Gas Recovery.

### **Step 2: Eliminate Technically Infeasible Options**

(a) **Flare design and monitoring**

Flare design and good combustion practices – Flare design and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The use of proper flare design and good combustion practices is a technically feasible control option for the ammonia storage flare (EU-016).

(b) **Process flaring minimization practices**

Process flaring minimization practices – To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of VOC will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT. The use of process flaring minimization practices is a technically feasible control option for the ammonia storage flare (EU-016).

(c) **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 Midwest Fertilizer Corporation facility is not feasible for the following reasons:

- (1) First, unlike a refinery's nearly continuous supply of flared gases, flaring at the proposed Midwest Fertilizer Corporation facility will be an infrequent occurrence.
- (2) Another difference is that the Midwest Fertilizer Corporation flaring events, the flared material may not be suitable for use as a fuel gas.

The use of a flare gas recovery system is not a technically feasible control option for the ammonia storage flare (EU-016).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All technically feasible control options have been selected as BACT by the applicant. A ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	0.0054 lb/MMBtu, 3 hr avg.	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	0.0054 lb/MMBtu, 3 hr avg.	Good combustion practice/flare design, flare minimization plan, natural gas
IA-0089	Homeland Energy Solutions	08/08/07	Startup and Shut down Flares	25 MMBtu	0.006 lb/MMBtu	None
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	No Numerical Limit	Good Combustion Practices
LA-0213	Valero Refining, St. Charles	11/17/09	Flare 1 – 5	Not Specified	No emissions	No limit on pilot flare

#### RBLC Review

A review of the RBLC entries in the table above indicates add-on controls are not required for flares of this size combusting natural gas. Most RBLC entries contain a pound per hour emission rate based on the combustion of natural gas such as the Homeland Energy Solutions flare. The Ohio Valley Resources permit required the use of a flare minimization plan. This plan is intended to find the root cause of excess emissions and to prevent a recurrence.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) Proper design and good combustion practices;
- (b) The use of natural gas; and
- (c) The use of flare minimization practices (FMP).

#### Step 5: Select BACT

IDEM, OAQ has established VOC BACT for the ammonia storage flare (EU-016) as:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.



- (2) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the “root cause” of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.
- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

IDEM, OAQ has identified the following greenhouse gas (GHG) control technologies or operational procedures for use in the ammonia storage flare (EU-016):

- (1) Carbon Capture and Sequestration (CCS);
- (2) Good Design and Combustion Practices;
- (3) Flare Minimization practices (FMP); and
- (4) Low Carbon Fuel for Pilot and Sweep Gas.

#### **Step 2: Eliminate Technically Infeasible Options**

##### **(a) Carbon Capture and Sequestration (CCS)**

CCS was evaluated for the entire source under the GHG BACT analysis for the reformer furnace. Greenhouse gas emissions from the ammonia storage flare (EU-016) are created in the flare from the combustion of fuel in the pilot and are relatively small. As was discussed in the greenhouse gas BACT for the reformer furnace, CCS is not available or applicable to Midwest Fertilizer Corporation. Therefore, it is not a feasible control technology.

(b) **Good Design and Operation**

The flares will be designed to comply with the requirements of 40 CFR 60.18. The design will ensure the control of process off-gas streams sent to them. Greenhouse Gas emissions from the flares are primarily a function of combusting the waste gases flared and the initial composition of these streams. Good design and operation will ensure the flare is operating to achieve optimum combustion which reduces greenhouse gas emissions. Good design and operation are considered feasible control technologies for the ammonia storage flare (EU-016).

(c) **Flare Minimization Practices (FMP)**

The flare minimization practices are a method of operation that reduces greenhouse gas emissions by minimizing emergency and maintenance, startup and shut down (MSS) releases to the flare. Shorter operating times will result in less greenhouse gas emissions. The FMP will document procedures to be implemented to minimize or prevent emissions from the flare while allowing for the safe operation of the plant. A plan would address operational requirements for a cold start of the facility, startup and shut down of individual units, and unplanned outages that may result in releases to the flares. Flare minimization practices are considered a feasible control option for the ammonia storage flare (EU-016).

(d) **Low Carbon Fuel**

The primary fuel can be selected to minimize the carbon content which reduces the carbon available for conversion to CO<sub>2</sub>. Combustion of natural gas as a primary fuel is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

All feasible control options have been selected. Therefore, a ranking is not necessary.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Ammonia Storage Flare (EU-016) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ammonia Storage Flare (EU-016)	1.5 MMBtu/hr	CO <sub>2</sub> – 116.89 lb/MMBtu, 3 hr average.	Good combustion practice/flare design, flare minimization plan, natural gas
T147-32322-00062	Ohio Valley Resources	09/25/13	Ammonia Storage Flare (EU-005)	0.445 MMBtu/hr	CO <sub>2</sub> – 52.05 lb/hr, 3 hr average.	Good combustion practice/flare design, flare minimization plan, natural gas

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Ammonia Storage Flare (EU-016) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T153-29394-00005	Hoosier Energy REC, Merom	11/10/11	Coal Bed Methane Flare	25 MMBtu/hr	CO <sub>2</sub> -3,235 lb/hr CH <sub>4</sub> -0.06 lb/hr N <sub>2</sub> O-0.05 lb/hr	Good Combustion Practices
LA-0257	Sabine Pass LNG Terminal	12/06/11	Marine Flare	1,590 MMBtu/hr	CO <sub>2</sub> e – 2,909 TPY	Proper Operation, Monitor Flame
LA-0257	Sabine Pass LNG Terminal	12/06/11	Wet/Dry Gas Flares (4)	0.26 MMBtu/hr	CO <sub>2</sub> e – 133 TPY	Proper Operation, Monitor Flame
IA-0105	Iowa Fertilizer Company	10/26/12	Ammonia Flare	0.4 MMBtu/hr	None	Good Work Practices

#### RBLC Review

A review of the RBLC indicates add-on controls are not typically used with flares. Greenhouse gas emissions are controlled by good combustion and design practices and the monitoring of the presence of a pilot flare.

#### Applicant Proposal

The applicant proposes the following as BACT:

- (a) The applicant proposes good design and operation practices, the use of flare minimization practices and the use of a low carbon fuel such as natural gas for the pilot and sweep gas.

#### Step 5: Select BACT

IDEM, OAQ has established GHG BACT for the ammonia storage flare (EU-016) as:

- (a) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (b) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (1) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (2) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (3) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

- (c) Flare emissions shall be controlled by use of the following practices:
  - (1) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (2) Flares shall be operated with a flame present at all times; and
  - (3) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (d) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operation, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Ammonia Storage Flare (EU-016)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the ammonia storage flare (EU-016) shall be as follows:

- (1) The pilot and purge gas fuels used in the ammonia storage flare (EU-016) shall be natural gas.
- (2) Venting to the ammonia storage flare (EU-016) shall not exceed 168 hours per twelve consecutive month period with compliance determined at the end of each month.
- (3) The Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shut downs, and other flaring events:
  - (A) Flare Use Minimization: The Permittee shall limit periods when the backup storage compressor and the ammonia refrigeration compressor are offline at the same time to the extent practicable;
  - (B) The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shut down, and other flaring events; and
  - (C) The Permittee shall investigate the "root cause" of malfunction events that cause flaring events other than at startup or shut down. This root cause analysis shall identify the apparent cause of unanticipated flaring event and shall recommend additional preventive measures that will minimize the chance of a repeat event. The Permittee shall implement the recommended preventive measures.

- (4) Flare emissions shall be controlled by use of the following practices:
  - (A) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed 5 minutes during any two consecutive hours;
  - (B) Flares shall be operated with a flame present at all times; and
  - (C) Flares shall be continuously monitored to assure the presence of a pilot flame with a thermocouple, infrared monitor, or other approved device.
- (5) PM emissions from the ammonia storage flare (EU-016) shall not exceed 0.0019 lb/MMBtu, based on a three-hour average.
- (6) PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the ammonia storage flare (EU-016) shall each not exceed 0.0075 lb/MMBtu, based on a three-hour average.
- (7) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 0.068 lb/MMBtu, during normal operation, based on a three-hour average.
- (8) NO<sub>x</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 125.00 lb/hr, while venting, based on a three-hour average.
- (9) CO emissions from the ammonia storage flare (EU-016) shall not exceed 0.37 lb/MMBtu, during normal operations, based on a three-hour average.
- (10) VOC emissions from the ammonia storage flare (EU-016) shall not exceed 0.0054 lb/MMBtu, during normal operations, based on a three-hour average.
- (11) CO<sub>2</sub> emissions from the ammonia storage flare (EU-016) shall not exceed 116.89 lb CO<sub>2</sub>/MMBtu, during normal operations, based on a three-hour average.

<b>BACT Analysis – Urea Synthesis Plant (EU-006)</b>
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**Insignificant Activity Description**

- (o) One (1) 2,640 metric ton per day Urea Synthesis Plant, identified as emission unit EU-006, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-006. [40 CFR 60, Subpart VVa]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC PSD Applicability**

The urea synthesis plant (EU-006) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea synthesis plant for these pollutants and BACT analyses are not required for these pollutants.

**Greenhouse Gas BACT**

The urea synthesis plant (EU-006) has the potential to emit 3.2 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Urea Ammonium Nitrate Plant (EU-007)**

#### **Insignificant Activity Description**

- (p) One (1) 5,160 metric ton per day Urea Ammonium Nitrate (UAN) Plant, identified as emission unit EU-007, approved for construction in 2014, emissions are uncontrolled, exhausting to stack S-007. [40 CFR 60, Subpart VVa]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and VOC PSD Applicability**

The urea ammonium nitrate plant (EU-007) does not have the potential to emit PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and VOC. Therefore, 326 IAC 2-2 (PSD) does not apply to the urea ammonium nitrate plant for these pollutants and BACT analyses are not required for these pollutants.

#### **Greenhouse Gas BACT**

The urea ammonium nitrate plant (EU-007) has the potential to emit 1,038 tons per year of carbon dioxide. IDEM, OAQ considers greenhouse gas emissions from the urea ammonium nitrate plant as insignificant and has determined that it would be technically infeasible and not cost effective to require greenhouse gas control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Emergency Generator (EU-014)**

#### **Insignificant Activity Description**

- (q) One (1) distillate oil-fired emergency generator, identified as emission unit EU-014, approved for construction in 2014, rated at 3,600 HP, exhausting to stack S-014. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

#### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

##### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- (a) Add-on controls;
- (b) Good Combustion Practices; and
- (c) Usage Limitations.

##### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.

(b) **Good Combustion Practices**

This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.

(c) **Usage Limitations**

Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LAER CLEARINGHOUSE DATA</b> <b>Diesel-Fired Emergency Generator (EU-014) – Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators CC009 - CC015	3,622 HP	0.0001 lb/hp-hr, PM <sub>10</sub> , filterable only, 0.4 lb/hr each	Good Combustion Practice, turbocharger
NV-0050	MGM Mirage	11/30/09	Diesel Emergency Generators LX024-LX025	2,206 HP	0.0001 lb/hp-hr, PM <sub>10</sub> , filterable only, 0.2 lb/hr each	Good Combustion Practice, turbocharger
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Generator (EU-014)	3,600 HP	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr average; 500 hours/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690 HP	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.2 g/KW-hr, 3 test average; 0.22 ton/12 month rolling	Good Combustion Practices
FL-0322	Southeast Renewable Fuels	12/23/10	Emergency Generator	2,000 KW	PM-0.2 g/KW-hr, filterable and condensable	Comply with 40 CFR 60, Subpart IIII
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Emergency Generator	750 KW 1,005 HP	PM-0.2 g/KW-hr	Good Combustion, Tier 2 Engine

#### RBLC Review

None of the emergency generators in the RBLC include add-on control technology. Emissions of particulate are controlled by limiting the hours of operation of the generator and practicing good combustion practices. The two units located at the MGM Mirage in Nevada were constructed. However, the state of Nevada does not require testing of insignificant activities and the emission rates were never verified.

#### Applicant Proposal

The applicant proposed the following as BACT:

- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr;
- PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions shall be controlled by exercising good combustion practices; and
- The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per year.

In addition, IDEM, OAQ required a cost effectiveness analysis of these engines as part of the BACT analysis performed by Ohio Valley Resources. IDEM, OAQ updated this analysis to reflect 500 hours of operation of the emergency generator.



Control Alternative	Captured Emissions (TPY)	Emission Reduction (TPY)	Capital Cost (\$)	Operating Cost (\$/yr)	Total Annualized Costs (\$/yr) (b)	Cost Effectiveness (\$/ton)	Energy and Environmental Impacts
0.05 g/hp-hr, PTE at 500 hours	0.13	0.17	45,000	(a)	\$6,407	\$37,688	lower overall emissions, units have same HP
Baseline, 500 Hours, 0.15 g/hp-hr	0.30	---	---	---	---	---	---

**Notes:**

- (a) The annual operating costs and salvage value are assumed identical for both engine designs.  
(b) Capital Recovery Factor – 0.14238 (7%, 10 year lifecycle)

The emergency generator will operate 500 hours annually regardless of the generator selected. The emission reduction attributable to the lower emitting generator is only 0.17 tons per year and costs \$37,688 dollars per ton of emission reduction achieved. The lower emitting generator cannot be justified using a cost effectiveness analysis in this specific application.

**Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (b) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices; and
- (c) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average.

**NO<sub>x</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- (a) Add-on controls;
- (b) Good Combustion Practices; and
- (c) Usage Limitations.

### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.
- (b) **Good Combustion Practices**  
This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.
- (c) **Usage Limitations**  
Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Generator (EU-014)	3,600 HP	4.46 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690 HP	4.46 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 –015	3,622 HP	0.01 lb/Hp-hr 37.4 lb/hr, each unit	Turbocharger After-cooler
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 –025	2,206 HP	0.0131 lb/Hp-hr 28.98 lb/hr	Turbocharging, After-cooling, lean burn

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,680 HP	6.0 g/KW-hr, avg. 3 tests; 6.61 ton/12 month rolling	Good Combustion Practices
FL-0322	Southeast Renewable	12/23/10	Emergency Generator	2,682 HP	6.4 g/KW-hr	Comply 40 CFR 60, Subpart IIII
AK-0071	Chugach Electric	12/20/10	Black-Start Generator	2,010 HP	6.4 g/KW-hr, instantaneous	Turbocharger and After-cooler

#### RBLC Review

None of the emergency generators in the RBLC use add-on controls. If a control method is specified, it is good combustion practices. The Ohio Valley Resources emergency generator has a slightly lower emission rate. However, this difference is insignificant. They are essentially identical.

#### Applicant Proposal

- (a) NO<sub>x</sub> emissions shall not exceed 4.46 g/hp-hr;
- (b) NO<sub>x</sub> emissions shall be controlled by exercising good combustion practices; and
- (c) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per year.

The emission rate for the emergency generator proposed by the applicant represents top BACT.

#### Step 5: Select BACT

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;
- (b) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall be controlled by exercising good combustion practices; and
- (c) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

- (a) Add-on controls;
- (b) Good Combustion Practices; and
- (c) Usage Limitations.

### **Step 2: Eliminate Technically Infeasible Options**

Possible control technologies identified in Step 1 are discussed in detail below:

- (a) **Add-on controls**  
EPA determined that add-on controls were economically infeasible for emergency internal combustion engines during the development of 40 CFR 60, Subpart IIII. Therefore, add-on controls are not a feasible option.
- (b) **Good Combustion Practices**  
This type of emission control is included in the RBLC for particulate matter control from emergency internal combustion engines. Good combustion practices are a technically feasible control option.
- (c) **Usage Limitations**  
Usage limitations restrict the number of hours the internal combustion engine can operate and result in lower overall emissions of all pollutants. This method of emission control is listed in the RBLC for internal combustion engines and is a technically feasible control option.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted good combustion practices and usage limitations; therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Emergency Generators CC009 to CC015	3,622 HP	0.0017 lb/Hp-hr 6.05 lb/hr, each	Good Combustion Practices, Turbocharger
NV-0050	MGM Mirage	11/30/09	Emergency Generators LX024 and LX025	2,206 Hp	0.0018 lb/HP-hr 3.95 lb/hr, each	Good Combustion Practices, Turbocharger
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Generator (EU-014)	3,600 HP	2.61 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator EU-009	4,690	2.61 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
AK-0076	Exxon-Port Thomson Production	08/20/12	Diesel-Fired Generators	2,314 HP	3.5 g/KW-hr	None
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,682 HP	3.5 g/KW-hr, 3 run avg.; 3.86 ton/12 month rolling	Good Combustion Practices
FL-0332	Highlands Biorefinery and Cogeneration	09/23/11	2000 KW Emergency Equipment	2,682 HP	3.5 g/KW-hr	Comply with 40 CFR 60, Subpart IIII

#### RBLC Review

None of the emergency generators in the RBLC include add-on control technology. Emissions of carbon monoxide are controlled by limiting the hours of operation of the generator and practicing good combustion practices. The two units located at the MGM Mirage in Nevada were constructed. However, the state of Nevada does not require testing of insignificant activities and the emission rates were never verified.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) The diesel-fired emergency generator (EU-014) shall not operate more than 500 hours per year;
- (b) CO emissions from the diesel-fired emergency generator (EU-014) shall be controlled by good combustion practices; and
- (c) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr.

### **Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) CO emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.
- (c) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average.

IDEM, OAQ is not requiring the applicant to meet the 0.77 g/hp-hr emission limitation of the MGM Grand because it appears to be an outlier. There have been other BACT determinations from other states issued after the MGM BACT with higher emission levels than those proposed by the applicant. In addition, the MGM engines were installed but were never tested to confirm actual emissions.

## **VOC BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency generator (EU-014) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – VOC						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
NV-0050	MGM Mirage	11/30/09	Diesel Generator	2,206 HP	0.0003 lb/HP-hr, 0.71 lb/hr, each	Turbocharger, Good Combustion
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Generator (EU-014)	3,600 HP	0.31 g/hp-hr, 3 hr avg. 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator (EU-009)	4,690 HP	0.31 g/hp-hr, 3 hr avg., 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	0.4 g/KW-hr, avg. 3 test runs; 0.44 ton/12 month rolling	None
LA-0254	Entergy Louisiana	08/06/11	Diesel Generator	1,250 HP	1 g/hp-hr, annual average.	Good Combustion
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Emergency Generators 1 to 8	757 HP	4 g/KW-hr	Comply 40 CFR 60, Subpart IIII
ID-0018	Idaho Power Company, Langley Gulch	06/25/10	Diesel Generator	750 KW	6.4 g/KW-hr	Good Combustion Tier 2 Engine

#### RBLC Review

None of the emergency generators in the RBLC use add-on controls. If a control method is specified, it is good combustion practices. The lowest entry is for a 2,206 HP diesel generator at the MGM Mirage. Its emission rate is equivalent to 0.14 g/hp-hr. The applicant proposes an emission rate of 0.31 g/hp-hr which is higher than the MGM Mirage but consistent with the recently issued Ohio Valley Resources VOC BACT. The MGM Mirage units were constructed but were never tested to verify actual emission rates.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) VOC emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.

- (c) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr.

The applicant's proposal represents a higher level of control than the Ohio Valley Resource VOC BACT. The MGM Mirage unit appears to be an outlier. The unit was installed but never tested. There are more recent BACT determinations with higher VOC emission rates in the RBLC. As such, IDEM, OAQ does not believe the MGM Mirage VOC BACT represents VOC BACT for the Midwest Fertilizer Corporation.

#### **Step 5: Select BACT**

IDEM, OAQ proposes the following as BACT for the diesel-fired emergency generator identified as EU-014:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) VOC emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices.
- (c) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency generator (EU-014) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.



RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Generator (EU-014) – Greenhouse Gases						
RBLC ID Permit #	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Generator (EU-014)	3,600 HP	CO <sub>2</sub> – 526.39 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Generator (EU-009)	4,690 HP	CO <sub>2</sub> – 526.39 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Emergency Generator	2,000 KW	CO <sub>2</sub> e – 788.5 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, 3 test average; CH <sub>4</sub> – 0.0001 g/KW-hr, 3 test average	Good Combustion Practices
AK-0076	Exxon, Point Thomson Production Facility	08/20/12	Emergency Generator	1,750 KW	CO <sub>2</sub> – No Numerical Limit	Good Combustion, 40 CFR 60, Subpart IIII
MI-0402	Wolverine Power, Sumpter Power Plant	11/17/11	Diesel RICE	732 HP	CO <sub>2</sub> e – 716 lb/hr, test method	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Generator	1,250 HP	CO <sub>2</sub> – 163 lb/MMBtu	Proper Operation and Good Combustion
T147-30464-00060	Indiana Gasification	06/27/12	Emergency Generator ( 5 Units )	2 @ 1,341 HP 3 @ 575 HP	Total CO <sub>2</sub> emissions limited to 84 tons CO <sub>2</sub> per year	Good Design to meet NSPS/MACT

#### RBLC Review

None of the emergency generators listed in the RBLC use add-on control technology to control greenhouse gas emissions. The only method of control used is good combustion practices.

#### Applicant Proposal

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) GHG emissions shall be controlled by the use of good combustion practices.
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr.

The applicant has accepted top BACT.

**Step 5: Select BACT**

IDEM, OAQ has established GHG BACT for the diesel-fired emergency generator (EU-014) as:

- (a) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (b) GHG emissions shall be controlled by the use of good combustion practices; and
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency generator shall not exceed 526.39 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Diesel-Fired Emergency Generator (EU-014)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency generator (EU-014) shall be as follows:

- (1) The hours of operation of the diesel-fired emergency generator (EU-014) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (2) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency generator (EU-014) shall be controlled by the use of good combustion practices;
- (3) The PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the operation of the diesel-fired emergency generator (EU-014) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 4.46 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency generator (EU-014) shall not exceed 2.61 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency generator (EU-014) shall not exceed 0.31 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency generator (EU-014) shall not exceed 526.39 g/hp-hr, based on a three-hour average.

**BACT Analysis – Fire Water Pump (EU-015)**

**Insignificant Activity**

- (r) One (1) distillate oil-fired emergency fire water pump, identified as emission unit EU-015, approved for construction in 2014, rated at 500 HP, exhausting to stack S-015. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

**PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

**Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLCL), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Fire Water Pump (EU-015) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLCL ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Fire Water Pump (EU-015)	500 HP	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Water Pump (EU-016)	481 HP	<u>PM/PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Emergency Fire Pump	350 HP	<u>PM<sub>10</sub>/PM<sub>2.5</sub></u> 0.15 g/Hp-hr, annual average	Ultra-Low Sulfur Diesel, Good Combustion Practices

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Diesel-Fired Emergency Fire Water Pump (EU-015) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
IA-0088	Archer Daniels Midland – Cedar Rapids	06/29/07	Fire Pump	540 HP	PM/PM <sub>10</sub> 0.15 g/HP-hr, 3 test average; 0.04 ton/12 month rolling	Tier 3 non-road Engine
IA-0095	Tate & Lyle Ingredients	09/19/08	Fire Pump	575 HP	PM/PM <sub>10</sub> 0.20 g/HP-hr, avg. 3 runs; 0.05 ton/12 month rolling	None
AZ-0046	Arizona Clean Fuels, Yuma	04/14/05	Fire Water Pump	5.46 MMBtu/hr 780 HP	PM-0.2 g/KW-hr	Certified by manufacturer to achieve limit
IA-0105	Iowa Fertilizer Company	10/26/12	Diesel Fire Pump	235 KW 315 HP	PM/PM <sub>10</sub> /PM <sub>2.5</sub> 0.2 g/KW-hr, avg. 3 tests; 0.03 ton/12 month rolling	Good Combustion Practice

#### RBLC Review

A review of the RBLC indicates add-on controls are not a feasible option for the fire water pump. The only method of control for particulate is the use of good combustion practices. The lowest emission rate is 0.15 g/hp-hr. This emission rate was used as BACT in several other permits listed in the RBLC.

#### Applicant Proposal

The applicant has proposed the following as BACT:

- (1) Good Combustion Practices;
- (2) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions shall each not exceed 0.15 g/hp-hr; and
- (3) Operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per year.

#### Step 5: Select BACT

IDEM, OAQ has established BACT as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month; and
- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average.

## NO<sub>x</sub> BACT

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LAER CLEARINGHOUSE DATA						
Fire Water Pump (EU-015) – NO <sub>x</sub>						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Fire Pump (EU-015)	500 HP	2.83 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	2.86 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	300 HP	3.75 g/KW-hr, avg. 3 tests; 0.49 ton/12 month rolling	Good Combustion Practices
LA-0251	Flopam, Inc.	04/26/11	Fire Pump	444 HP	3.0 g/KW-hr; 5.82 lb/hr; 0.29 TPY	None
ID-0018	Idaho Power Company	06/25/10	Fire Pump	267 HP	4.0 g/KW-hr	Tier 3 Engine, Good Combustion
SC-0113	Pyramax Ceramics	02/08/12	Fire Pump	500 HP	4.0 g/KW-hr	40 CFR 60, Subpart IIII
OH-0254	Duke Energy Washington County	08/14/03	Fire Pump	400 HP	14.5 g/Hp-hr 12.8 lb/hr 3.2 TPY	Combustion Control

### **RBLC Review**

A review of the RBLC indicates add-on controls are not a feasible option for the fire water pump. The only method of control for particulate is the use of good combustion practices. The lowest emission rate is 2.86 g/hp-hr for the fire pump at the Ohio Valley Resources facility. The applicant is proposing an emission rate below the lowest listed in the RBLC.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (1) Good Combustion Practices;
- (2) NO<sub>x</sub> emissions shall not exceed 2.83 g/hp-hr; and
- (3) Operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (1) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average; and
- (3) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **CO BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Diesel-Fired Fire Pump (EU-015) – CO						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Fire Pump (EU-015)	500 HP	2.6 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	2.6 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	3.5 g/KW-hr, avg. 3 tests; 0.45 ton/12 month rolling	Good Combustion Practices
MI-0389	Consumers Energy	12/29/09	Fire Pump	525 HP	2.6 g/hp-hr, test method	Good Design and Operation
LA-0254	Ninemile Point Electric Generating	08/16/11	Emergency Fire Pump	350 HP	2.6 g/HP-hr	Good Combustion Practices
FL-0322	Southeast Renewable Fuels	12/23/10	Emergency Diesel Fire Pump	600 HP	2.6 g/HP-hr	Comply with 40 CFR 60, Subpart IIII
SD-0005	Basin Electric Power Coop	10/14/11	Fire Pump	577 HP	None	40 CFR 60, Subpart IIII

#### **RBLC Review**

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 2.6 g/hp-hr. The applicant is proposing essentially the same emission rate.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (1) CO emissions from the diesel-fired emergency fire pump (EU-015) shall be minimized by good combustion practices;
- (2) CO emissions shall not exceed 2.6 g/hp-hr; and
- (3) The diesel-fired emergency fire pump shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

#### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the diesel-fired fire pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency firewater pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (2) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall be controlled by the use of good combustion practices; and
- (3) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average.

#### **VOC BACT**

##### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

##### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

##### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.



#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Diesel-Fired Emergency Fire Pump (EU-015) – VOC</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Emergency Fire Pump (EU-015)</b>	<b>500 HP</b>	<b>0.141 g/hp-hr, 3 hr average; 500 hr/12 month rolling</b>	<b>Good Combustion Practices</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump EU-016	481 HP	0.141 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	0.25 g/KW-hr, 3 run avg.; 0.03 ton/12 month rolling	Good Combustion
LA-0254	Entergy Louisiana	08/06/11	Emergency Fire Pump	350 HP	1 g/hp-hr, annual average	Good Combustion
SC-0113	Pyramax Ceramics, Inc.	02/08/12	Fire Pump	500 HP	4 g/KW-hr, 100 hr/yr	Certified by manufacturer, 40 CFR 60, Subpart IIII
ID-0018	Idaho Power, Langley Gulch	06/25/10	Fire Pump Engine	235 KW	4 g/KW-hr	Tier 3 Engine, Good Combustion
OK-0129	Associated Electric Cooperative	01/23/09	Fire Pump	267 HP	0.66 lb/hr	Good Combustion

#### **RBLC Review**

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 0.14 g/hp-hr for the Ohio Valley Resources facility. The applicant is proposing essentially the same emission rate. The applicant's emission rate is 0.009 g/hp-hr higher. This equates to an additional 0.002 TPY of VOC on a slightly larger pump. This difference is insignificant. It should be noted that none of the emission units emitting VOC under 1.0 g/hp-hr have been constructed.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (1) Good combustion practices;
- (2) VOC emissions shall not exceed 0.141 g/hp-hr; and
- (3) The fire pump shall not operate more than 500 hours per year.

### **Step 5: Select BACT**

IDEM, OAQ has established VOC BACT for the diesel-fired fire pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average.

### **Greenhouse Gas BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired fire water pump (EU-015) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Diesel-Fired Fire Water Pump (EU-015) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Fire Pump (EU-015)	500 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Emergency Fire Pump (EU-016)	481 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr average; 200 hr/12 month rolling	Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	CO <sub>2e</sub> – 91 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, 3 test avg.; Methane – 0.0001 g/KW-hr, 3 test avg.	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Fire Pump	350 HP	CO <sub>2</sub> – 163 lb/MMBtu CH <sub>4</sub> – 0.0061 lb/MMBtu N <sub>2</sub> O – 0.0014 lb/MMBtu	Proper Operation and Good Combustion
MD-0040	CPV St Charles	11/12/08	Fire Water Pump	300 HP	Methane - 3 g/Hp-hr	None

#### RBLC Review

A review of RBLC entries for small fire water pumps indicates add-on control devices are not used. The only control method employed is good combustion practices. The lowest emission rate listed is 527.40 g/hp-hr as CO<sub>2</sub>. The applicant is proposing the same emission rate and control using good combustion practices. This is top BACT.

#### Applicant Proposal

The applicant has proposed the following as BACT:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr.

**Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency fire water pump (EU-015) as:

- (1) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (2) GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by the use of good combustion practices.
- (3) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Diesel-fired Emergency Fire Water Pump (EU-015)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for diesel-fired emergency fire water pump (EU-015) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency fire water pump (EU-015) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency fire water pump (EU-015) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency firewater pump (EU-015) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency fire water pump (EU-015) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

**BACT Analysis – Emergency Raw Water Pump (EU-063)**

**Insignificant Activity**

- (s) One (1) distillate oil-fired emergency raw water pump, identified as emission unit EU-063, approved for construction in 2014, rated at 500 HP, exhausting to stack S-063. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ] [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

**Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Emergency Raw Water Pump (EU-063) – PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	PM, PM <sub>10</sub> , PM <sub>2.5</sub> 0.15 g/hp-hr, 3 hr avg., 500 hr/12 month rolling	Good Combustion
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	PM <sub>10</sub> 0.14 lb/hr max. 0.004 TPY max. 0.15 g/hp-hr 52 hr/yr	Good Design and Operating Practices
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	PM <sub>10</sub> -0.264 lb/hr 0.095 TPY	None

### **RBLC Review**

The raw water pump is used to supply water to the facility during emergencies. A review of the RBLC to find diesel-fired pumps in similar service shows two entries. Neither used add-on controls. One used good combustion practices to control particulate. The lowest emission rate is 0.15 g/hp-hr. This represents top BACT and is identical to the applicant's proposal.

### **Applicant Proposal**

The applicant has proposed the following as BACT:

- (a) Good Combustion Practices;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions each shall each not exceed 0.15 g/hp-hr; and
- (c) Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT as follows:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

### **NO<sub>x</sub> BACT**

#### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

#### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

#### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

#### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Emergency Raw Water Pump (EU-063) – NO <sub>x</sub> BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	2.83 g/hp-hr, 3 hr avg. 500 hr/12 month rolling	Good Combustion
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	8.9 lb/hr max. 0.23 TPY max. 9.5 g/hp-hr	Good Design and Operation
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	3.17 lb/hr 1.34 TPY	None

#### RBLC Review

A review of the RBLC for raw water pumps indicates add-on controls are not used. Emissions are controlled by good combustion practices. The lowest emission rate is 9.5 g/hp-hr. The applicant is proposing an emission rate of 2.83 g/hp-hr controlled by good combustion practices. This represents top BACT.

#### Applicant Proposal

The applicant proposed the following as BACT:

- (a) Good Combustion Practices;
- (b) NO<sub>x</sub> emissions shall not exceed 2.83 g/hp-hr; and
- (c) Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per year.

The applicant has accepted top BACT.

#### Step 5: Select BACT

IDEM, OAQ has established BACT as follows:

- (a) NO<sub>x</sub> from the diesel-fired emergency raw water pump (EU-063) emissions shall be controlled by good combustion practices;
- (b) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## CO BACT

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Emergency Raw Water Pump (EU-063) – CO BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	1.88 lb/hr max; 0.05 TPY max; 2.01 g/hp-hr, annual average	Good Design and Operation
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	2.60 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Water Pump	481 HP	2.60 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Good Combustion
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	3.5 g/KW-hr, avg. 3 tests; 0.45 ton/12 month rolling	Good Combustion Practices
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	0.8020 lb/hr, 0.2890 TPY	None



### **RBLC Review**

There are limited entries for small diesel-fired emergency raw water pumps. None of the entries use add-on control technology to control carbon monoxide emissions. The lowest entry in the RBLC table is 2.01 g/hp-hr for the pump installed at Crescent City Power. Carbon monoxide emissions from the Crescent City water pump are limited to 100 pounds of CO per year. This equates to 53 hours of operation. The next closest entry for a raw water pump in the table is the Structural Metals, Inc. raw water pump at 3.0 g/hp-hr. The applicant is proposing an emission rate of 2.60 g/hp-hr for a slightly larger unit. The 2.60 g/hp-hr limit is an NSPS Tier III compliant engine.

IDEM, OAQ does not believe Crescent City Power sets BACT for these units because the unit was never constructed and the PSD permit was revoked on November 1, 2006.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall be minimized by good combustion practices;
- (b) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr; and
- (c) The diesel-fired emergency raw water pump (EU-063) shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established CO BACT for the diesel-fired emergency fire pump (EU-063) as:

- (a) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **VOC BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Emergency Raw Water Pump (EU-063) – VOC BACT						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0192	Crescent City Power	06/06/05	Diesel Water Pump	425 HP	0.05 lb/hr max. 0.001 TPY max. 0.05 g/hp-hr, annual average	Good Design and Operation
T 129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	0.141 g/hp-hr, 3 hr avg.; 500 hr/12 month rolling	Good Combustion
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Pump	481 HP	0.141 g/hp-hr, 3 hr avg.; 200 hr/yr	Good Combustion
TX-0445	Structural Metals, Inc.	01/28/04	Emergency Water Pump	120 HP	0.2960 lb/hr 0.1070 TPY	None

**RBLC Review**

There are only two existing entries in the RBLC for diesel-fired pumps used in raw water service. The lowest emission rate is 0.05 g/hp-hr. The next lowest is 1.11 g/hp-hr. The applicant is proposing an emission rate of 0.15 g/hp-hr. IDEM, OAQ does not believe the Crescent City Power sets BACT for these units because the unit was never constructed and the PSD permit was revoked on November 1, 2006. Because of the limited entries in this category, IDEM, OAQ compared VOC BACT entries for small fire pumps, less than 500 HP.

### **Applicant Proposal**

The applicant proposed the following for BACT:

- (a) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall be minimized by good combustion practices;
- (b) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (c) The diesel-fired emergency raw water pump (EU-063) shall not operate more than 500 hours per year.

The applicant has accepted top BACT.

### **Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency fire pump (EU-063) as:

- (a) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (b) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (c) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.

## **Greenhouse Gas BACT**

### **Step 1: Identify Potential Control Technologies**

Today's stationary diesel-fired emergency compression ignition internal combustion engines are sold as package units with an engineering design tailored to meet the emission limitations of 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. The manufacturer provides an engine that is in compliance with the applicable NSPS and NESHAP and the owner/operator is expected to maintain and operate the unit to guarantee compliance with applicable emission limitations.

### **Step 2: Eliminate Technically Infeasible Options**

The only feasible control option for the diesel-fired emergency raw water pump (EU-063) is good combustion practices.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted the only feasible control option. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA Emergency Raw Water Pump (EU-063) – Greenhouse Gases						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Emergency Raw Water Pump (EU-063)	500 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr average; 500 hr/12 month rolling	Good Combustion Practices
T147-32322-00062	Ohio Valley Resources	09/25/13	Fire Pump	481 HP	CO <sub>2</sub> – 527.40 g/hp-hr, 3 hr avg.; 200 hr/12 month rolling	Combustion Practices, Use Limit
IA-0105	Iowa Fertilizer Company	10/26/12	Fire Pump	235 KW	CO <sub>2</sub> e – 91 ton/12 month rolling; CO <sub>2</sub> – 1.55 g/KW-hr, avg. 3 tests; Methane – 0.0001 g/KW-hr, avg. 3 tests	Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/11	Fire Pump	350 HP	CO <sub>2</sub> – 163 lb/MMBtu CH <sub>4</sub> – 0.0064 lb/MMBtu N <sub>2</sub> O – 0.0014 lb/MMBtu	Proper Operation and Good Combustion
MD-0040	CPV St Charles	11/12/08	Fire Pump	300 HP	Methane – 3 g/Hp-hr	None

#### RBLC Review

There are no RBLC entries for greenhouse gas emissions from small RICE engines in water service. IDEM, OAQ compared the proposed raw water pump to small fire water pumps. The lowest entry in this class is the Ohio Valley Resources (OVR) fire pump. The applicant has proposed the same emission rate. This is top BACT.

#### Applicant Proposal

The applicant has proposed the following as BACT:

- Operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by the use of good combustion practices.
- CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

**Step 5: Select BACT**

IDEM, OAQ has established BACT for the diesel-fired emergency raw water pump (EU-063) as:

- (a) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month.
- (b) GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by the use of good combustion practices.
- (c) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

This analysis focuses on the emissions of CO<sub>2</sub> only. While other GHGs, such as methane and N<sub>2</sub>O, 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<sub>2</sub>, the other GHGs will be reduced accordingly. Therefore, CO<sub>2</sub> serves as a useful surrogate for other GHGs in this regard.

<p><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Emergency Raw Water Pump (EU-063)</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for emergency raw water pump (EU-063) shall be as follows:

- (1) PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC and GHG emissions from the diesel-fired emergency raw water pump (EU-063) shall be controlled by good combustion practices;
- (2) The hours of operation of the diesel-fired emergency raw water pump (EU-063) shall not exceed 500 hours per twelve consecutive month period with compliance determined at the end of each month;
- (3) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall each not exceed 0.15 g/hp-hr, based on a three-hour average;
- (4) NO<sub>x</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.83 g/hp-hr, based on a three-hour average;
- (5) CO emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 2.60 g/hp-hr, based on a three-hour average;
- (6) VOC emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 0.141 g/hp-hr, based on a three-hour average; and
- (7) CO<sub>2</sub> emissions from the diesel-fired emergency raw water pump (EU-063) shall not exceed 527.40 g/hp-hr, based on a three-hour average.

<b>BACT Analysis – Ten Cell Cooling Tower (EU-010)</b>
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**Insignificant Activity**

- (t) One (1) ten cell evaporative cooling tower, identified as emission unit EU-010, approved for construction in 2014, exhausting to stacks S-010A through S-010J. [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**Step 1: Identify Potential Control Technologies**

Emissions from cooling towers are generally controlled by a drift elimination system.

**Step 2: Eliminate Technically Infeasible Options**

(a) **High Efficiency Drift Eliminators**

Cooling towers are a source of particulate matter (PM/PM<sub>10</sub>/PM<sub>2.5</sub>) 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<sub>10</sub>/PM<sub>2.5</sub>) 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.

Drift eliminators contain packing which is used to limit the amount of 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.

The use of a drift elimination system is technically feasible control option for cooling tower (EU-010).

(b) **Dissolved Solids Management**

A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blow down) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blow down process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method for cooling tower (EU-010).

**Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted both control strategies. Therefore, a ranking of control efficiencies is not required.

**Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Cooling Tower (EU-010) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBLC ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-113	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-213	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-114	17,611 GPM	0.0005% Drift, 1,000 mg/l TDS	Drift Eliminators
T147-30464-00060	Indiana Gasification	06/27/12	ASU and Main Cooling Tower EU-016A/B	55,000 GPM-A 405,000 GPM-B	0.0005% Drift 1,500 mg/l	High Efficiency Drift Eliminators
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Ten Cell Cooling Tower (EU-010)	147,937 GPM	0.0005% drift 2,000 mg/l TDS, monthly average	High Efficiency Drift Eliminators
T147-32322-00062	Ohio Valley Resources	09/25/13	Cooling Towers EU-008A-H EU-019A-F	179,720 GPM combined	0.0005% Drift 2,000 mg/l TDS, daily average	High Efficiency Drift Eliminators
IA-0106	CF Industries, Port Neal	07/12/13	16 Cell Draft Cooling Tower	322,000 GPM	0.0005% drift 2,030 mg/l TSD	High Efficiency Drift Eliminators

#### RBLC Review

All of the entries in the RBLC for cooling towers indicates high efficiency drift eliminators are the only commercially viable particulate control method used today. All of the entries have limited emissions by setting a maximum allowable drift of 0.0005%. It is less clear that a limit on the total dissolved solids (TSD) concentration is expected for the cooling water. The lowest entries in the RBLC are all from the same source using the same water supply. The Nucor plant is required to achieve a maximum drift of 0.0005% with a maximum TDS of 1,000 mg/liter.

IDEM, OAQ does not believe the Nucor cooling tower or the Indiana Gasification (IG) cooling tower sets particulate BACT for Midwest Fertilizer Corporation (MFC). To start, the cooling towers at Nucor are much smaller than the units proposed by MFC. The MCF towers will use well water while the IG cooling towers use river water. River water is naturally lower in dissolved solids than well water. Ground water travels slowly from the recharge point to the well and the water is in direct contact with the ions that contribute to TDS. These ions include chloride, sodium, nitrate, calcium, magnesium, bicarbonate, sulfate, boron, bromide and iron. A higher TSD for Ohio Valley Resources and Midwest Fertilizer Corporation is justified.

The most recent RBLC entries use a maximum 0.0005% drift and a TDS concentration of 2,000 mg/liter.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for cooling tower (EU-010) as:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The cooling tower identified as EU-010 does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the cooling tower for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Ten Cell Cooling Tower (EU-010)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for ten cell cooling tower (EU-010) shall be as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-010) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (2) The total dissolved solids in the water used in cooling tower (EU-010) shall not exceed 2,000 mg/l, averaged on a monthly basis.

<b>BACT Analysis – Six Cell Cooling Tower (EU-011)</b>
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### **Insignificant Activity**

- (u) One (1) six cell evaporative cooling tower, identified as emission unit EU-011, approved for construction in 2014, exhausting to stacks S-011A through S-011F. [326 IAC 2-2]



## **PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

### **Step 1: Identify Potential Control Technologies**

Emissions from cooling towers are generally controlled by a drift elimination system.

### **Step 2: Eliminate Technically Infeasible Options**

#### **(a) High Efficiency Drift Eliminators**

Cooling towers are a source of particulate matter (PM/PM<sub>10</sub>/PM<sub>2.5</sub>) 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<sub>10</sub>/PM<sub>2.5</sub>) 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.

Drift eliminators contain packing which is used to limit the amount of 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.

The use of a drift elimination system is technically feasible control option for cooling tower (EU-011).

#### **(b) Dissolved Solids Management**

A cooling tower is a device intended to remove heat from a process through the evaporation of water. The minerals contained in the vaporized water remain in the recirculated cooling water and form scale or increase the total dissolved solids. Operators remove water from the system (blow down) and replace it with makeup water to maintain a desired total dissolved solids concentration and a constant volume of recirculated water. The blow down process is automated and the system normally contains a conductivity sensor and a solenoid valve to automatically remove solids from the system. The proper management of the total dissolved solids concentration of the recirculation water is a technologically feasible control method for cooling tower (EU-011).

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The applicant has accepted both control strategies. Therefore, a ranking of control efficiencies is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

RACT/BACT/LEAR CLEARINGHOUSE DATA						
Cooling Tower (EU-011) – Particulate (PM, PM <sub>10</sub> and PM <sub>2.5</sub> )						
RBL ID	Facility	Issued Date	Process Description	Capacity	Limitation	Control Method
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-113	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.11 lb/hr PM <sub>10</sub> -0.4 TPY	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-213	26,857 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.11 lb/hr PM <sub>10</sub> -0.4 TPY	Drift Eliminators
LA-0248	Nucor, Direct Reduction Plant	01/27/11	Cooling Tower DRI-114	17,611 GPM	0.0005% Drift, 1,000 mg/l TDS PM <sub>10</sub> -0.07 lb/hr PM <sub>10</sub> -0.29 TPY	Drift Eliminators
T147-30464-00060	Indiana Gasification	06/27/12	ASU and Main Cooling Tower EU-016A/B	55,000 GPM-A 405,000 GPM-B	0.0005% Drift 1,500 mg/l, daily average	High Efficiency Drift Eliminators
T129-33576-00059	Midwest Fertilizer Corporation	Proposed	Six Cell Cooling Tower (EU-011)	147,937 GPM	0.0005% drift 2,000 mg/l TDS, monthly average	High Efficiency Drift Eliminators
T147-32322-00062	Ohio Valley Resources	09/25/13	Cooling Towers EU-008A-H EU-019A-F	179,720 GPM combined	0.0005% Drift 2,000 mg/l TDS, daily average	High Efficiency Drift Eliminators
IA-0106	CF Industries, Port Neal	07/12/13	16 Cell Draft Cooling Tower	322,000 GPM	0.0005% drift 2,030 mg/l TDS	High Efficiency Drift Eliminators

#### RBLC Review

All of the entries in the RBLC for cooling towers indicates high efficiency drift eliminators are the only commercially viable particulate control method used today. All of the entries have limited emissions by setting a maximum allowable drift of 0.0005%. It is less clear that a total dissolved solids (TSD) concentration is expected for the cooling water. The lowest entries in the RBLC are all from the same source using the same water supply. The Nucor plant is required to achieve a maximum drift of 0.0005% with a maximum TDS of 1,000 mg/liter.

IDEM, OAQ does not believe the Nucor cooling tower or the Indiana Gasification (IG) cooling tower sets particulate BACT for Midwest Fertilizer Corporation (MFC). To start, the cooling towers at Nucor are much smaller than the units proposed by MFC. The MFC towers will use well water while the IG cooling towers use river water. River water is naturally lower in dissolved solids than well water. Ground water travels slowly from the recharge point and the water is in direct contact with the ions that contribute to TDS. These ions include chloride, sodium, nitrate, calcium, magnesium, bicarbonate, sulfate, boron, bromide and iron. A higher TSD for Ohio Valley Resources and Midwest Fertilizer Corporation is justified. The most recent RBLC entries use a maximum 0.0005% drift and a TDS concentration of 2,000 mg/liter.

#### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

#### **Step 5: Select BACT**

IDEM, OAQ has established PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT for cooling tower (EU-011) as:

- (a) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (b) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

#### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

The cooling tower identified as EU-011 does not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to the cooling tower for these pollutants and BACT analyses are not required for these pollutants.

<b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Six Cell Cooling Tower (EU-011)</b>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for the six cell cooling tower (EU-011) shall be as follows:

- (1) PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the cooling tower (EU-011) shall be controlled by high efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.
- (2) The total dissolved solids in the water used in cooling tower (EU-011) shall not exceed 2,000 mg/l, averaged on a monthly basis.

<b>BACT Analysis – Distillate Oil Storage Tank (EU-066)</b>
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#### **Insignificant Activity**

- (v) One (1) distillate oil storage tank, identified as EU-066, approved for construction in 2014, with a maximum storage capacity of 8,700 gallons. [326 IAC 2-2]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gas (GHG) emissions. Therefore, 326 IAC 2-2 (PSD) does not apply to fugitive emissions from equipment leaks for these pollutants and BACT analyses are not required for these pollutants.

### **VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions will be less than 0.01 tons per year. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Nitric Acid Storage Tank (EU-054)**

#### **Insignificant Activity**

- (w) One (1) nitric acid storage tank, identified as EU-054, approved for construction in 2014, with a maximum storage capacity of 8,000 metric tons, exhausting to stack S-054. The tanks do not contain an organic liquid. [326 IAC 2-2]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the nitric acid storage tank for these pollutants and BACT analyses are not required for these pollutants.

#### **NO<sub>x</sub> and VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

### **BACT Analysis – Urea Ammonium Nitrate Storage Tanks (EU-034, EU-035, and EU-036)**

#### **Insignificant Activity**

- (x) Three (3) Urea Ammonium Nitrate (UAN) storage tanks, identified as emission units EU-034, EU-035, and EU-036, approved for construction in 2014, each with a maximum capacity of 40,000 metric tons, each with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

#### **PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the urea ammonium nitrate (UAN) storage tanks for these pollutants and BACT analyses are not required for these pollutants.

#### **NO<sub>x</sub> and VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible and NO<sub>x</sub> emissions will be less than 0.13 tons per year. IDEM, OAQ considers VOC and NO<sub>x</sub> emissions from these units as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC and NO<sub>x</sub> control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

**BACT Analysis – Diesel Exhaust Fluid Tank (EU-037)**

**Insignificant Activity**

- (y) One (1) diesel exhaust fluid (DEF) storage tank, identified as EU-037, approved for construction in 2014, with a maximum capacity of 7,000 metric tons, with a volume greater than 151 cubic meters, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to the diesel exhaust fluid (DEF) storage tank for these pollutants and BACT analyses are not required for these pollutants.

**VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

**BACT Analysis – OASE<sup>®</sup> Solution / Methyldiethanolamine (MDEA) Storage Tank (EU-043)**

**Insignificant Activity**

- (z) One (1) OASE<sup>®</sup> solution / Methyldiethanolamine (MDEA) storage tank, identified as emission unit EU-043, approved for construction 2014, with a capacity of 395,000 gallons, storing a liquid with a true vapor pressure less than 3.5 kPa. [326 IAC 2-2]

**PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO and GHG PSD Applicability**

The applicant provided information with the application indicating this emission source will not have emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, or greenhouse gases (GHGs). Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to this unit for these pollutants and BACT analyses are not required for these pollutants.

**VOC PSD Applicability**

The applicant provided information with the application indicating VOC emissions are negligible. IDEM, OAQ considers VOC emissions from this unit as insignificant and has determined that it would be technically infeasible and not cost effective to require VOC control. Therefore, IDEM, OAQ has determined that no further BACT analysis is required.

<b>BACT Analysis -- Paved Roads and Parking Lots</b>
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**Insignificant Activity**

- (aa) Fugitive dust from paved roads and parking lots. [326 IAC 6-4] [326 IAC 2-2]

**PM, PM<sub>10</sub>, and PM<sub>2.5</sub> BACT**

**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<sub>10</sub>) and PM<sub>2.5</sub> from fugitive sources are generally controlled with measures to prevent the emissions from occurring. Generally, fugitive PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions from roadways are controlled through one of the following mechanisms:

- (1) Paving of Roadways;
- (2) Wet Suppression or Chemical suppression; and
- (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**

(a) **Add-on Control Technology:**

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. The use of add-on controls is not a technically feasible control option for the paved roadways and parking lots with public access.

(b) **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 affecting the degree of agglomeration and 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 a water/surfactant mix and foams. Wet suppression systems typically achieve PM control efficiencies of greater than 85%. The use of a wet suppression or chemical suppression is a technically feasible control option for the paved roadways and parking lots with public access.

(c) **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. The use of paving roadways and good housekeeping is a technically feasible control option for the paved roadways and parking lots with public access.

### **Step 3: Rank the Remaining Control Technologies by Control Effectiveness**

The following measures have been proposed by the applicant for control of PM, PM<sub>10</sub> and PM<sub>2.5</sub> resulting from the paved roadways and parking lots with public access:

- (a) Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.
- (b) Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

The applicant has accepted all control technologies. Therefore, a ranking is not required.

### **Step 4: Evaluate the Most Effective Controls and Document the Results**

The following table lists the proposed BACT determination for this facility along with the existing BACT determinations for similar emission units. All data in the table is based on the information obtained from the permit application submitted by the Applicant, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), Indiana issued permits, and electronic versions of permits available at the websites of other permitting agencies.

<b>RACT/BACT/LEAR CLEARINGHOUSE DATA</b>						
<b>Paved Roadways and Parking Lots with Public Access -- Particulate (PM, PM<sub>10</sub> and PM<sub>2.5</sub>)</b>						
<b>RBLC ID</b>	<b>Facility</b>	<b>Issued Date</b>	<b>Process Description</b>	<b>Capacity</b>	<b>Limitation</b>	<b>Control Method</b>
<b>T129-33576-00059</b>	<b>Midwest Fertilizer Corporation</b>	<b>Proposed</b>	<b>Paved Roads and Parking Lots</b>	<b>10,403 VMT/yr</b>	<b>90% Control</b>	<b>Paving, Speed Limits, sweeping, wet suppression</b>
T147-32322-00062	Ohio Valley Resources	09/25/13	Paved Roads and Parking Lots	17,160 VMT/yr	90% Control	Paving, Speed Limits, sweeping, wet suppression
T147-30464-00060	Indiana Gasification	06/27/12	Haul Roads	Not indicated	90% Control	Paving, wet suppression, prompt cleanup
OH-0317	Ohio River Clean Fuels	11/20/08	Paved Roads	736,205 VMT/yr	PM -- 79.00 TPY PM <sub>10</sub> -- 15.69 TPY 90% Control	Watering, Sweeping, Speed Limit
OH-0297	FDS Coke Company	06/14/04	Roadways	Unknown	PM -- 24.88 TPY PM <sub>10</sub> -- 4.85 TPY	Watering
OH-0328	V & M Star	04/10/09	Roadways	Unknown	PM <sub>10</sub> -- 12.4 TPY (AP-42 Emission Factors)	Control Measures to Minimize Emissions
IA-0105	Iowa Fertilizer Company	10/26/12	Paved Roads	2 miles of road	No numeric limit	Water Flushing, Sweeping

#### **RBLC Review**

The table above shows recent entries in the RACT/BACT/LEAR Clearinghouse (RBLC database for haul roads. Control measures include watering, sweeping, speed limits and good housekeeping. The highest emission reduction appearing in the RBLC is 90% control.

### **Applicant Proposal**

The applicant proposed the following as BACT:

- (a) All roadways will be paved;
- (b) The source will use speed limits; and
- (c) The source will use daily sweeping with wet suppression.

### **Step 5: Select BACT**

The PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (1) Paving all plant haul roads;
- (2) Daily sweeping with wet suppression; and
- (3) Prompt cleanup of any spilled materials.

### **NO<sub>x</sub>, CO, VOC and GHG PSD Applicability**

Fugitive emissions from paved roads and parking lots will not have NO<sub>x</sub>, CO, VOC or GHG emissions. Therefore, the requirements of 326 IAC 2-2 (PSD) do not apply to paved roads and parking lots for these pollutants and BACT analyses are not required for these pollutants.

<p style="text-align: center;"><b>Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) Summary Analysis for the Paved Roads and Parking Areas</b></p>
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Pursuant to PSD/Operating Permit T129-33576-00059 and 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the best available control technology (BACT) for paved roads and parking areas shall be as follows:

PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from paved haul roads shall be controlled to an overall control efficiency of 90% by employing the following work practices:

- (1) Paving all plant haul roads;
- (2) Daily sweeping with wet suppression; and
- (3) Prompt cleanup of any spilled materials.



## Indiana Department of Environmental Management Office of Air Quality

### Appendix C to the Technical Support Document (TSD) Air Quality Impact Analysis

#### Source Background and Description

Source Name:	Midwest Fertilizer Corporation
Source Location:	Intersection Old SR 69 and Mackey Ferry Rd. East Mt. Vernon, Indiana 47620
County:	Posey County, Black Township
SIC Code:	2873
Permit Number:	T 129-33576-00059
Permit Writer:	David Matousek
Air Quality Modeler:	Steven Sherman

#### Air Quality Analysis

### Midwest Fertilizer Corporation

### Mount Vernon, Indiana (Posey County)

Tracking and Plant ID: 129-33576-00059

#### Proposed Project

Midwest Fertilizer Corporation, (herein referred to as Midwest) first submitted their Prevention of Significant Deterioration (PSD) modeling in August 2013. Midwest proposes to construct and operate a nitrogen fertilizer manufacturing facility in Posey County, in Mount Vernon, Indiana.

Environmental Resources Management (ERM) was the consultant who prepared the modeling portion of the permit application for Midwest. This technical support document provides the air quality analysis review of the submitted modeling by ERM for Midwest and by the Indiana Department of Environmental Management (IDEM).

#### Analysis Summary

Based on the potential emissions after controls, a PSD air quality analysis was triggered for PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and NO<sub>2</sub>. The significant impact analysis for PM<sub>10</sub>, annual NO<sub>2</sub>, CO, and annual PM<sub>2.5</sub> determined that modeling concentrations did not exceed the significant impact levels. A refined analysis was required for the short-term NO<sub>2</sub> standard and the short-term PM<sub>2.5</sub> standard. In this refined analysis, there were exceedances for short-term NO<sub>2</sub> and PM<sub>2.5</sub>. A cause and contribute analysis was performed for the short-term standards of NO<sub>2</sub> and PM<sub>2.5</sub> which showed Midwest did not significantly contribute to those violations. An additional impact analysis was conducted and showed no significant impact. An analysis of secondary formation of ozone and PM<sub>2.5</sub> showed no significant impact.

## **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. Analysis of Secondary Ozone and PM<sub>2.5</sub> formation
- 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<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOCs, and HAPs are the pollutants that will be emitted from Midwest and are summarized below in Table 1. PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>2</sub>, and CO potential emissions after controls exceed the PSD significant emission rates and therefore require an air quality analysis. Emissions for HAPs did not exceed the threshold that triggers an air quality analysis for IDEM.

**TABLE 1**  
**Facility Emission Rates**

<b>POLLUTANT</b>	<b>SOURCE EMISSION RATE</b> (Facility totals in tons/year)	<b>EMISSION RATE THRESHOLD</b> (tons/year)	<b>PRELIMINARY AQ ANALYSIS REQUIRED</b>
PM <sub>10</sub>	113.1	15	Yes
PM <sub>2.5</sub>	109.8	10	Yes
NO <sub>x</sub>	534.2	40	Yes
SO <sub>2</sub>	7.3	40	No
CO	1043.0	100	Yes
VOC	104.4	40	Yes <sup>2</sup>
HAPs	23.5	25 <sup>1</sup>	No <sup>3</sup>
Largest HAP	9.9 of Hexane	10 <sup>1</sup>	No <sup>3</sup>

<sup>1</sup>Total HAP emissions of 25 tons per year (TPY) or 10 TPY per pollutant trigger HAP analysis, but are not a PSD Significant Emission Rate (SER)

<sup>2</sup> VOC emissions are only included in a secondary pollutant analysis.

<sup>3</sup>HAP's analysis is not a federal requirement.

## **Section B – Good Engineering Practice (GEP), Met Data, Model Used, Receptor Grid and Terrain**

### **Stack Height Compliance with Good Engineering Practice (GEP)**

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:

$$H_g = H + 1.5L$$

Where: H<sub>g</sub> is the GEP stack height  
 H is the structure height  
 L is the structure's lesser dimension (height or width)

### **Meteorological Data**

The National Weather Service (NWS) 1-minute Automated Surface Observation Station (ASOS) meteorological data used in the air quality analysis consisted of 2008 through 2012 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

The Office of Air Quality (OAQ) used AERMOD version 12345 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 Regulations Part 51, Appendix W "Guideline on Air Quality Models".

### Receptor Grid

OAQ modeling used the same receptor grids generated by the consultant. The receptor grid is outlined below:

- 100 meter spacing from the property boundary to 2 kilometers,
- 200 meters spacing from 2 to 5 kilometers,
- 500 meters spacing from 5 to 10 kilometers,
- 1000 meters spacing from 10 to 25 kilometers,
- 2500 meters spacing beyond 25 kilometers.

### Treatment of Terrain

Receptor terrain elevation inputs were interpolated from NED (National Elevation Dataset) data obtained from the USGS. NED 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 Significant Impact Levels, (SILs) further air quality analysis is required. Refined modeling for PM<sub>2.5</sub> annual, PM<sub>10</sub>, and annual NO<sub>2</sub> was not required because the results did not exceed SILs. The PM<sub>2.5</sub> 24-hour and 1-hour NO<sub>2</sub> exceeded their SILs and required refined modeling. SILs 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<sub>2</sub> was assumed based on the March 01, 2011, Tyler Fox memorandum.

**TABLE 2**  
**Significant Impact Analysis<sup>3</sup>**

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (µg/m <sup>3</sup> )	SIGNIFICANT IMPACT LEVEL (µg/m <sup>3</sup> )	REFINED AQ ANALYSIS REQUIRED
NO <sub>2</sub>	Annual <sup>1</sup>	0.75	1	No
NO <sub>2</sub>	1-hour <sup>2</sup>	14.97	7.55	Yes
PM <sub>10</sub>	Annual <sup>1</sup>	0.58	1	No
PM <sub>10</sub>	24-hour <sup>1</sup>	2.71	5	No
PM <sub>2.5</sub>	Annual <sup>2</sup>	0.29	0.3 <sup>4</sup>	No
PM <sub>2.5</sub>	24-hour <sup>2</sup>	2.07	1.2 <sup>4</sup>	Yes
CO	1-hour <sup>1</sup>	775.5	2000	No
CO	8-hour <sup>1</sup>	378.9	500	No

<sup>1</sup>First highest values per EPA NSR manual October 1990.

<sup>2</sup> 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<sub>2</sub>, 1-hour SO<sub>2</sub>, 24-hour PM<sub>2.5</sub>, and the annual PM<sub>2.5</sub> SIL. See the March 01, 2011 and the March 23, 2010 memorandums.

<sup>3</sup>Impacts are from Midwest only.

<sup>4</sup>The PM<sub>2.5</sub> SIL was vacated on January 22, 2012

Due to the vacatur of the PM<sub>2.5</sub> SIL, another test must be made to protect the PM<sub>2.5</sub> annual NAAQS. If the difference between the NAAQS and the measured PM<sub>2.5</sub> background in the area is greater than the applicable SIL value, then EPA believes it would be sufficient in most cases to conclude that a source with an impact below the SIL will not cause a new NAAQS violation as shown below in Table 3. The site used is in Henderson, KY as described later in Table 5.

**TABLE 3**  
**PM<sub>2.5</sub> Annual NAAQS Analysis**

NAAQS ( $\mu\text{g}/\text{m}^3$ )	BACKGROUND MONITOR ( $\mu\text{g}/\text{m}^3$ )	DIFFERENCE BETWEEN MONITOR AND NAAQS ( $\mu\text{g}/\text{m}^3$ )	SIL ( $\mu\text{g}/\text{m}^3$ )	DIFFERENCE GREATER THAN SIL ?	REFINED AQ ANALYSIS REQUIRED
12.0	11.3	0.7	0.3	Yes	No

<sup>1</sup> 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<sub>2</sub>, 1-hour SO<sub>2</sub>, 24-hour PM<sub>2.5</sub>, and the annual PM<sub>2.5</sub> SIL. See the March 01, 2011, and the March 23, 2010 memorandums.

### 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 4**  
**Preconstruction Monitoring Analysis**

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS ( $\mu\text{g}/\text{m}^3$ )	SIGNIFICANT MONITORING CONCENTRATION ( $\mu\text{g}/\text{m}^3$ )	ABOVE SMC LEVEL
NO <sub>2</sub>	Annual <sup>1</sup>	14.97	14	Yes
PM <sub>10</sub>	24-hour <sup>1</sup>	2.7	10	No
PM <sub>2.5</sub>	24-hour <sup>2</sup>	2.07	0 <sup>3</sup>	Yes <sup>3</sup>
CO	8-hour	378.9	575	No

<sup>1</sup> First highest values per EPA NSR manual October 1990. Maximum modeled impacts are from Midwest only.

<sup>2</sup> 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.

<sup>3</sup> The significant monitoring concentration was vacated on January 22, 2012, and then replaced with a value of zero on December 9, 2013.

For NO<sub>2</sub> and PM<sub>2.5</sub>, Midwest did exceed the preconstruction monitoring threshold level. Midwest may use existing data in lieu of preconstruction monitoring.

## 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 Midwest. The background design value was used for PM<sub>2.5</sub> and NO<sub>2</sub>. It was agreed between Midwest and OAQ that this approach be used in place of the preconstruction monitoring requirement.

**TABLE 5**  
**Existing Monitoring Data Used For Background Concentrations \***

Pollutant	Location	Monitoring Site	Averaging Period	Concentration (ug/m <sup>3</sup> )
PM <sub>2.5</sub>	Henderson, KY	21-101-0014	24-hour	23.3
PM <sub>2.5</sub>	Henderson, KY	21-101-0014	Annual	11.3
NO <sub>2</sub>	Evansville, IN	18-163-0021	1-hour	67.8

\* PM<sub>2.5</sub> and NO<sub>2</sub> used the design value.

## Section D - NAAQS and PSD Increment

### NAAQS Compliance Analysis and Results

OAQ supplied emission inventories of all point sources in Indiana within a 50-kilometer radius of Midwest. The NAAQS inventories are generated from EMITS (Emission Inventory Tracking System) in accordance with 326 IAC 2-6. A search through Computer Assisted Approval and Tracking System (CAATS) was performed to update the modeling inventory of the largest and nearest sources to potential emissions after controls. Sources taken from Illinois and Kentucky inventories were reported in potential emissions.

The highest receptor modeling results are shown in Table 6.

**TABLE 6**  
**NAAQS Analysis**

Pollutant	Time-Averaging Period	MFC Concentration (ug/m <sup>3</sup> )	Maximum Concentration (ug/m <sup>3</sup> )	Background Concentration (ug/m <sup>3</sup> )	Total (ug/m <sup>3</sup> )	NAAQS Limit (ug/m <sup>3</sup> )	NAAQS Violation
NO <sub>2</sub>	1-hour	0.00	654.0 <sup>1</sup>	67.8	721.8	188.6	Yes
PM <sub>2.5</sub>	24-hour	0.49	37.9 <sup>1,2</sup>	23.3	61.2	35	Yes

<sup>1</sup>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.

<sup>2</sup>Listed in this table is the highest 1-hour period for any receptor at which the project was above the SIL. This did not include impacts from sources onto their own property.

OAQ performed culpability modeling and the results for modeled exceedances are shown in Table 7, 8 and 9. The exceedances with the largest contributions from Midwest have been listed below.

**TABLE 7**  
**1-hour NO<sub>2</sub> NAAQS Analysis**

UTM East	UTM North	Midwest Concentration (µg/m <sup>3</sup> )	Total Modeled Concentration (µg/m <sup>3</sup> )	Background Concentration (µg/m <sup>3</sup> )	Rank	Total (µg/m <sup>3</sup> )	NAAQS Limit (µg/m <sup>3</sup> )	Percentage of NAAQS due to Midwest
411325	4197710	5.8	121.9	67.8	18TH	189.7	188.6	3.1%
414725	4197610	5.8	152.3	67.8	13TH	220.1	188.6	3.1%
413325	4197210	5.8	141.8	67.8	15TH	209.6	188.6	3.1%
414525	4197610	5.7	151.3	67.8	13TH	219.1	188.6	3.0%
416125	4197610	5.7	147.5	67.8	21ST	215.3	188.6	3.0%
416525	4197510	5.4	142.1	67.8	28TH	209.9	188.6	2.9%
416625	4197310	5.3	143.8	67.8	28TH	211.6	188.6	2.8%
416325	4197410	5.3	143.0	67.8	27TH	210.8	188.6	2.8%
409325	4197710	5.2	125.2	67.8	15TH	193.0	188.6	2.8%
420125	4199610	5.2	153.1	67.8	93RD	220.9	188.6	2.7%
415325	4197610	5.1	142.6	67.8	16TH	210.4	188.6	2.7%
415925	4197410	5.1	144.0	67.8	24TH	211.8	188.6	2.7%
416325	4197310	5.0	144.3	67.8	27TH	212.1	188.6	2.7%
413925	4197210	5.0	142.9	67.8	15TH	210.7	188.6	2.7%
416525	4197610	5.0	139.3	67.8	27TH	207.1	188.6	2.7%
413725	4197210	4.9	142.2	67.8	15TH	210.0	188.6	2.6%
412325	4197210	4.9	137.6	67.8	15TH	205.4	188.6	2.6%
413325	4198410	4.8	122.6	67.8	18TH	190.4	188.6	2.6%
415525	4197410	4.8	141.7	67.8	24TH	209.5	188.6	2.5%
413525	4197210	4.8	141.6	67.8	15TH	209.4	188.6	2.5%
416625	4198610	4.7	171.2	67.8	21ST	239.0	188.6	2.5%
416725	4198510	4.7	177.5	67.8	21ST	245.3	188.6	2.5%
416725	4198610	4.7	170.1	67.8	25TH	237.9	188.6	2.5%
416825	4198510	4.7	174.2	67.8	22ND	242.0	188.6	2.5%
416525	4198710	4.7	185.8	67.8	15TH	253.6	188.6	2.5%
416825	4197410	4.7	141.5	67.8	24TH	209.3	188.6	2.5%
416825	4198410	4.7	195.3	67.8	18TH	263.1	188.6	2.5%
416625	4198710	4.7	154.6	67.8	26TH	222.4	188.6	2.5%
Highest Exceedance		0.0	654.0	67.8	1st	721.8	188.6	0.0%

**TABLE 8**  
**24-hour PM<sub>2.5</sub> NAAQS Analysis**

UTM East	UTM North	Midwest Concentration (µg/m <sup>3</sup> )	Total Modeled Concentration (µg/m <sup>3</sup> )	Background Concentration (µg/m <sup>3</sup> )	Rank	Total (µg/m <sup>3</sup> )	NAAQS Limit (µg/m <sup>3</sup> )	Percentage of NAAQS due to Midwest
418725	4197910	1.10	12.5	23.3	32ND	35.8	35	3.1%
417725	4197510	0.98	12.7	23.3	26TH	36.0	35	2.8%
417867	4197546	0.97	12.8	23.3	27TH	36.1	35	2.8%
418025	4197610	0.92	12.8	23.3	20TH	36.1	35	2.6%
417725	4197510	0.91	12.2	23.3	29TH	35.5	35	2.6%
418825	4197810	0.89	13.2	23.3	35TH	36.5	35	2.6%
417768	4197546	0.89	12.4	23.3	30TH	35.7	35	2.5%
418165	4197546	0.87	15.7	23.3	15TH	39.0	35	2.5%
418725	4197710	0.86	13.0	23.3	25TH	36.3	35	2.5%
418025	4197610	0.86	17.5	23.3	10TH	40.8	35	2.4%
418925	4197710	0.85	12.2	23.3	42ND	35.5	35	2.4%
417762	4197090	0.85	14.0	23.3	19TH	37.3	35	2.4%
417763	4197182	0.84	14.3	23.3	17TH	37.6	35	2.4%
417925	4197710	0.84	13.2	23.3	21ST	36.5	35	2.4%
417764	4197273	0.84	14.7	23.3	16TH	38.0	35	2.4%
418725	4197810	0.83	12.4	23.3	31ST	35.7	35	2.4%
417925	4197710	0.83	17.1	23.3	11TH	40.4	35	2.4%
419125	4197610	0.83	13.0	23.3	27TH	36.3	35	2.4%
417925	4197610	0.83	12.7	23.3	20TH	36.0	35	2.4%
417725	4196810	0.82	14.4	23.3	20TH	37.7	35	2.3%
418825	4197710	0.82	14.1	23.3	22ND	37.4	35	2.3%
418025	4197810	0.82	12.0	23.3	23RD	35.3	35	2.3%
418825	4198210	0.82	16.0	23.3	17TH	39.3	35	2.3%
417763	4197182	0.80	12.8	23.3	25TH	36.1	35	2.3%
417725	4197510	0.80	15.1	23.3	16TH	38.4	35	2.3%
418425	4197810	0.80	12.8	23.3	27TH	36.1	35	2.3%
418725	4197910	0.79	23.6	23.3	7TH	46.9	35	2.3%
417725	4197610	0.79	15.7	23.3	13TH	39.0	35	2.3%
Highest Exceedance		0.49	37.9	23.3	1st	61.2	35	1.4%



**TABLE 9**  
**Annual PM<sub>2.5</sub> NAAQS Analysis**

UTM East	UTM North	Midwest Concentration (µg/m <sup>3</sup> )	Total Modeled Concentration (µg/m <sup>3</sup> )	Background Concentration (µg/m <sup>3</sup> )	Rank	Total (µg/m <sup>3</sup> )	NAAQS Limit (µg/m <sup>3</sup> )	Percentage of NAAQS due to Midwest
418525	4197810	0.298	5.489	11.3	N/A	16.789	12	2.48%
418625	4197810	0.297	5.514	11.3	N/A	16.814	12	2.48%
418625	4197710	0.294	5.542	11.3	N/A	16.842	12	2.45%
418725	4197710	0.294	5.578	11.3	N/A	16.878	12	2.45%
418525	4197910	0.291	5.450	11.3	N/A	16.750	12	2.43%
418725	4197810	0.291	5.573	11.3	N/A	16.873	12	2.42%
418625	4197910	0.290	5.551	11.3	N/A	16.851	12	2.41%
418525	4197710	0.288	5.514	11.3	N/A	16.814	12	2.40%
418725	4197910	0.282	5.488	11.3	N/A	16.788	12	2.35%
417825	4196810	0.282	5.573	11.3	N/A	16.873	12	2.35%
417925	4196810	0.282	5.643	11.3	N/A	16.943	12	2.35%
418725	4197610	0.281	5.617	11.3	N/A	16.917	12	2.34%
418825	4197710	0.281	5.679	11.3	N/A	16.979	12	2.34%
418625	4197610	0.278	5.573	11.3	N/A	16.873	12	2.32%
418425	4197810	0.276	5.524	11.3	N/A	16.824	12	2.30%
418825	4197810	0.276	5.866	11.3	N/A	17.166	12	2.30%
417758	4196817	0.276	5.510	11.3	N/A	16.810	12	2.30%
417938	4196817	0.274	5.644	11.3	N/A	16.944	12	2.29%
417848	4196817	0.274	5.579	11.3	N/A	16.879	12	2.29%
418825	4197010	0.273	6.362	11.3	N/A	17.662	12	2.28%
418425	4197710	0.273	5.586	11.3	N/A	16.886	12	2.27%
418625	4198010	0.272	5.565	11.3	N/A	16.865	12	2.26%
418805	4196990	0.272	6.370	11.3	N/A	17.670	12	2.26%
418825	4197610	0.270	5.688	11.3	N/A	16.988	12	2.25%
418725	4198010	0.267	5.333	11.3	N/A	16.633	12	2.23%
418525	4198010	0.266	5.403	11.3	N/A	16.703	12	2.21%
418825	4197910	0.265	5.708	11.3	N/A	17.008	12	2.20%
418762	4197546	0.264	5.694	11.3	N/A	16.994	12	2.20%
Highest Exceedance		0.142	7.726	11.3	1st	19.026	35	1.18%

Even though the model predicts a NAAQS violation, Midwest did not have an impact above the current or previous significance level at the same receptor and time period as any modeled exceedance. Therefore, Midwest does not cause or contribute to a violation of the NO<sub>2</sub> or PM<sub>2.5</sub> NAAQS.

## 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<sub>2.5</sub>. This rule also limits a source to no more than 80 percent of available PSD increment to allow for future growth.

### Source Impact

A PSD increment analysis for Midwest and surrounding sources was required. The PSD increment inventories include sources that affect the increment and are compiled from permits issued by OAQ. For PM<sub>2.5</sub>, no other increment consuming source was within 50 kilometers of the project. Results of the increment modeling are summarized in Table 10 below.

**TABLE 10**  
**Increment Analysis**

Pollutant	Year	Time-Averaging Period	Maximum Concentration (µg/m <sup>3</sup> )	PSD Increment (µg/m <sup>3</sup> )	Percent Impact on the PSD Increment	Increment Violation
PM <sub>2.5</sub>	2008-2012	24-hour	2.07	9	23.0 %	No
PM <sub>2.5</sub>	2008-2012	Annual	0.29	4	7.4%	No

<sup>1</sup> Any differences between the maximum concentration numbers in Tables 6 and 9 would be due to different sources used for the NAAQS and the increment inventories.

The results of the increment analysis show all pollutants for all averaging periods were below 80% of the available increment. No further analysis is required.

## Part E – Qualitative Analysis

### Additional Impact Analysis

All PSD permit applicants must prepare 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 Midwest modeling submittal provided an additional impact analysis performed by ERM.

### 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.

Midwest expects 300 employees will be drawn from the local area. Since the city's population is less than 7,000, it is not expected the growth impacts will cause a violation of the NAAQS or the PSD increment.

### Soils and Vegetation Analysis

Soil types included thick loamy soils. Due to the agricultural nature of the land, crops in the Posey County area consist mainly of corn and soybeans. (2007 Agricultural Census for Spencer County). The maximum modeled concentrations for Midwest are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation. Livestock in the county consist mainly of hogs, cattle and dairy (2007 Agricultural Census for Posey 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 Posey County Indiana includes 1 mammal, 1 insect, 1 bird, and 13 mollusks. The state endangered species on the list are 14 mollusks, 2 insects, 2 fish, 2 amphibians, 5 reptiles, 6 birds, and 3 mammals have an endangered habitat within Posey County. 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.

## Visibility Analysis

A visibility analysis was performed for impacts on local visibility. The VISCREEN model is designed as a screening model to determine the visual impact using parameters from a single source's plume. It is used basically to determine whether or not a plume is visible as an object itself. The visibility impairment analysis considers the impacts that occur within the impact area of the source as defined by the user distances. The user distances are determined by the nearest interstate or airport. EPA has defined these locations in guidance to the state.

The PM<sub>10</sub>, SO<sub>2</sub>, and NO<sub>x</sub> emissions limits were used to run a local visibility Level 1 analysis. VISCREEN Version 1.01 was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. The Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to determine how the human eye responds differently to different wavelengths of light. The Delta-E of 2.0 and the plume contrast of 0.05 were not exceeded at the Henderson Airport.

**TABLE 11**  
**Level 1 Local Visibility Analysis**

Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E Critical	Delta E Plume	Contrast Critical	Contrast Plume
Sky	10	84	23.4	84	2.00	1.279	0.05	0.002
Sky	140	84	23.4	84	2.00	0.393	0.05	-0.007
Terrain	10	84	23.4	84	2.00	0.398	0.05	0.006
Terrain	140	84	23.4	84	2.00	0.090	0.05	0.004

Thus, it is concluded that there will be no visibility impacts at the closest location from the facility.

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 Midwest is Mammoth Cave National Park which is 165 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 Midwest facility is not required to conduct a Class 1 area analysis since the combined emissions of visibility impairing pollutants are less the screening threshold. The visual impact is equal to  $Q / D$ , the total emissions divided 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.

The primary visibility impairment pollutants are PM<sub>10</sub>, SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and NO<sub>x</sub>. The proposed potential emissions of these pollutants from Midwest are  $Q = 113.1 + 7.3 + 0 + 534.2 \text{ TPY} = 654.6 \text{ TPY}$ . The distance to the nearest Class 1 area is  $D = 165 \text{ km}$ . The source impact is  $Q / D = 654.6 / 165 = 3.97$ . 3.97 is less than 10, so this project will not affect visibility in the nearest Class 1 area.

## Additional Analysis Conclusion

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 – Qualitative Assessment of the Potential For Ozone/Secondary PM<sub>2.5</sub> Formation

A secondary ozone and/or PM<sub>2.5</sub> analysis is necessary if a source emits precursors for these pollutants above significant emission rates. The U.S. Environmental Protection Agency (U.S. EPA) has provided guidance to assess the impacts of precursor emissions on ozone and secondary PM<sub>2.5</sub> formation. The U.S. EPA has outlined three different approaches in its *Draft Guidance for PM<sub>2.5</sub> Permit Modeling*, dated March 4, 2013. The recommended approaches include:

1. Qualitative assessment
2. Hybrid of qualitative and quantitative assessments utilizing existing technical work
3. Quantitative photochemical grid modeling

The U.S. EPA stated in the draft guidance that in most cases, a qualitative assessment will suffice to address these impacts. A qualitative assessment requires that several factors be considered in the determination of impacts from precursor emissions on ozone and secondary PM<sub>2.5</sub> formation. This qualitative assessment will review monitoring data, emissions, and meteorological data for the area surrounding the Midwest Fertilizer Company (MFC) site located in Posey County, Indiana. MFC's proposed emissions were calculated to be 534.2 tons per year of oxides of nitrogen (NO<sub>x</sub>) and 104.4 tons per year of volatile organic compounds (VOCs), above significant emission rates, triggering this analysis. Sulfur Dioxide (SO<sub>2</sub>) emissions were proposed at 7.3 tons per year, below the PSD significant emission rate.

### Qualitative Assessment of the Potential for Ozone Formation

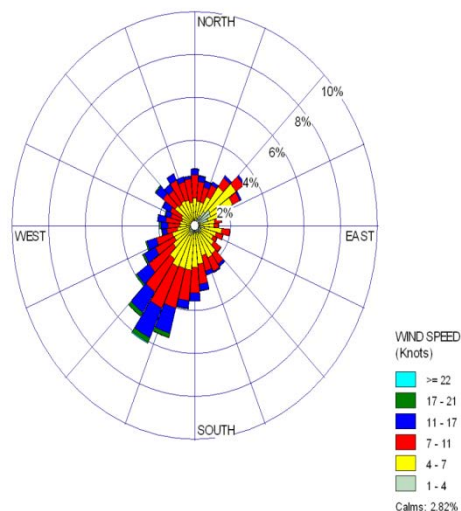
The qualitative assessment reviewed several factors including the MFC's proposed NO<sub>x</sub> and VOC emissions, meteorology, and monitoring data in the southwest Indiana area to determine if impacts due to ozone formation from these emissions would cause or contribute to a violation of the 8-hour ozone NAAQS.

#### 1. Wind Roses

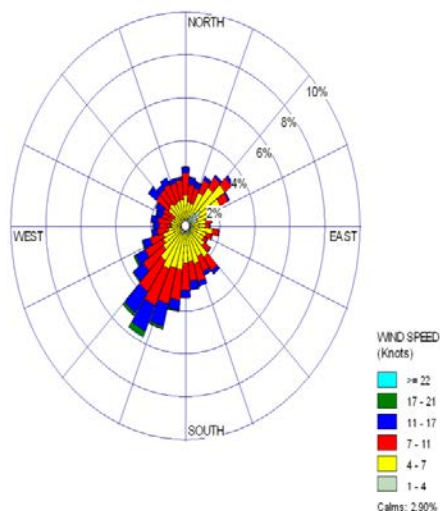
Figures 1 and 2 below show the wind roses taken from the National Weather Service station located at the Evansville Airport. Data was collected during the ozone season months of April through September for 2010 through 2012 and 2011 through 2013.

## Evansville Wind Roses Covering Months during Ozone Season

**Figure 1**  
**2010 to 2012**



**Figure 2**  
**2011 to 2013**



Prevailing winds were found to occur from the southwest. There was much consistency in the direction of the winds during the four-year period even though 4<sup>th</sup> high ozone readings at several southwest Indiana ozone monitors varied between 10 and 15 parts per billion during this time frame. MFC would be considered upwind of the ozone monitors in Posey, Vanderburgh, and Warrick counties. While MFC's NO<sub>x</sub> and VOC emissions would undergo photochemical reactions to form ozone, the impacts on these ozone monitors would be anticipated to be small due to the relatively small amount of MFC's NO<sub>x</sub> and VOC emissions as compared to NO<sub>x</sub> and VOC emissions from the three counties.

### 2. 8-Hour Ozone Monitoring Data

The nearest ozone monitor to MFC is the St. Philips monitor in Posey County. The current design value for 2011-2013 at the St. Philips monitor is 70 parts per billion (ppb). Ozone monitors considered downwind of MFC, in Posey, Vanderburgh, and Warrick Counties have current design values below the 8-hour ozone NAAQS of 75 ppb, as shown below in Table 12.

**Table 12**  
**Background 8-Hour Ozone Concentrations and Design Values in Southwest Indiana (2010-2013)**

Design Values (ppb)	2010	2011	2012	2013	2010-2012	2011-2013
Posey Co. - St. Philips	69	76	70	65	71	70
Evansville - Buena Vista	64	77	80	66	73	74
Evansville - Inglefield	71	72	78	68	73	72
Warrick Co. - Boonville	71	75	73	63	73	70
Warrick Co. - Lynnville	70	72	75	61	72	69
Warrick Co. - Dayville	70	72	81	66	74	73
Henderson Co. - KY	74	77	87	66	79	77

It is important to note that all ozone monitors in the southwest Indiana area are designated as attaining the 8-hour ozone NAAQS. MFC's 8-hour ozone impacts are anticipated to be small and not cause a violation of the 8-hour ozone NAAQS.

The Henderson County, Kentucky monitor has a design value of 77 ppb, above the 8-hour ozone NAAQS. However, due to MFC's location downwind of Henderson County, Kentucky, MFC would not be expected to significantly contribute to ozone concentrations in Henderson County on ozone conducive days.

### **3. Emissions**

MFC's proposed emissions would be 534.2 tons per year of NO<sub>x</sub> and 104.4 tons per year of VOCs. Downwind impacts from MFC, as shown in wind rose analysis above, would impact Posey, Vanderburgh, and Warrick Counties. Comparison of MFC's NO<sub>x</sub> emissions with the 2011 U.S. EPA's National Emissions Inventory (NEI) NO<sub>x</sub> emissions taken from all point, onroad, nonroad, nonpoint, and wildfire emissions sources would represent 1.9% of all NO<sub>x</sub> emissions in this three-county area. MFC's VOC emissions were compared with the 2011 NEI VOC inventory for Posey, Vanderburgh, and Warrick Counties and showed MFC VOC emissions would represent 0.9% of all point, onroad, nonroad, nonpoint, and wildfire VOC emissions. NO<sub>x</sub> and VOC emissions are above their respective PSD significant emission rate thresholds; however, it is anticipated that not all of MFC's ozone precursor emissions will result in local ozone formation. Ozone formation from photochemical reactions from the NO<sub>x</sub> and VOC emissions is not immediate and generally occurs at a distance of tens to hundreds of kilometers downwind. This small portion of MFC's NO<sub>x</sub> and VOC emissions is not expected to cause or contribute to 8-hour ozone NAAQS violations in the area.

### **Summary of Ozone Results**

MFC's NO<sub>x</sub> and VOC emissions were analyzed and their impacts were assessed with the background concentrations, design values of the surrounding area, meteorology, and 2011 NEI emissions comparisons. All ozone monitors in the southwest Indiana area have current 8-hour ozone design values that attain the 8-hour ozone NAAQS. NO<sub>x</sub> and VOC emissions from MFC are expected to comprise a small portion of the Southwest Indiana air shed NO<sub>x</sub> and VOC emissions. The downwind impacts from MFC on the St. Philips ozone monitor in Posey County and nearby ozone monitors in southwest Indiana and northwest Kentucky are anticipated to be minimal. This assessment concludes that MFC will not have a significant impact on the 8-hour ozone attainment status of Posey County or any surrounding counties.

### **Qualitative Assessment of the Potential for Secondary PM<sub>2.5</sub> Formation**

An assessment of MFC's NO<sub>x</sub> and SO<sub>2</sub> emissions was conducted to determine impacts on secondary PM<sub>2.5</sub>. In addition to direct emissions of PM<sub>2.5</sub>, other pollutants, chiefly NO<sub>x</sub> and SO<sub>2</sub>, can lead to formation of particulate nitrates and sulfates further downwind. The photochemical reactions that transform these pollutants into secondary PM<sub>2.5</sub> usually take place over hours or days after the pollutants are emitted into the atmosphere. However, it is possible that some of the NO<sub>x</sub> and SO<sub>2</sub> transformations into nitrates and sulfates from this source may occur more rapidly and be transported directly downwind. No peer-reviewed regulatory model presently exists to examine the photochemical PM<sub>2.5</sub> impacts from an individual source of SO<sub>2</sub> and NO<sub>x</sub>. All photochemical models are regional in scale and a source of this size does not show any measurable modeled impacts. Therefore, other available information from monitoring data, emissions inventories, meteorological analyses, and other modeling results can be used to qualitatively assess potential secondary PM<sub>2.5</sub> impacts.

#### **1. Annual and 24-Hour PM<sub>2.5</sub> Monitoring Data**

There are several PM<sub>2.5</sub> monitors within 50 miles of MFC, providing background concentrations representative of the air quality in the southwest Indiana air shed. Table 2 below shows the nearest PM<sub>2.5</sub> monitor considered downwind to MFC is the Buena Vista monitor in Evansville, Vanderburgh County. The 2010 – 2012 annual PM<sub>2.5</sub> design value at the Buena Vista monitor in Vanderburgh County is 11.8 micrograms per cubic meter (µg/m<sup>3</sup>), below the annual PM<sub>2.5</sub> NAAQS of 12.0 µg/m<sup>3</sup>. The University of Evansville PM<sub>2.5</sub> monitor has an annual design value of 12.2 µg/m<sup>3</sup>, exceeding the annual PM<sub>2.5</sub> NAAQS. Based on preliminary monitoring data through November 30, 2013, anticipated 2011-2013 annual PM<sub>2.5</sub> design values are expected to be lower

throughout the entire southwest Indiana area with all monitoring sites recording design values below the annual  $PM_{2.5}$  NAAQS.

**Table 13**  
**Annual  $PM_{2.5}$  Background Concentrations/Design Values in Southwest Indiana (2009-2013)**

Design Values ( $\mu g/m^3$ )	2009	2010	2011	2012	2013	Design Value 2009-2011	Design Value 2010-2012	Design Value 2011-2013
Evansville - Buena Vista	12.4	12.8	11.9	10.8	10.6	12.4	11.8	11.1
Evansville - Univ. of Evansville	12.5	13.4	12.3	11.0	10.4	12.7	12.2	11.2
Dubois Co. - Jasper	12.5	13.7	12.6	10.8	10.6	12.9	12.4	11.4
Spencer - Dale	11.8	13.0	12.5	10.4	10.0	12.4	12.0	11.0
Henderson Co. - KY	11.7	12.5	11.0	10.4	-	11.7	11.3	-

Note: The design values for a given period listed in the table above are the average of the background concentration values for those years in the period.

The 24-hour  $PM_{2.5}$  design value (2010-2012) for the closest  $PM_{2.5}$  monitor considered downwind to MFC (Buena Vista monitor in Vanderburgh County) is  $27.0 \mu g/m^3$ , below the 24-hour  $PM_{2.5}$  NAAQS of  $35.0 \mu g/m^3$ . All other  $PM_{2.5}$  monitors in the area have 24-hour  $PM_{2.5}$  design values below the Buena Vista monitor's design value and well below the 24-hour  $PM_{2.5}$  NAAQS. Table 13 below shows all monitors have design values that are trending downward and anticipated 2011-2013 design values are expected to be lower throughout the entire southwest Indiana area. Since the design values are well below the 24-hour  $PM_{2.5}$  NAAQS, IDEM did not feel the need to provide the 2013 24-hour  $PM_{2.5}$  values at this time.

**Table 14**  
**24-Hour  $PM_{2.5}$  Background Concentrations/Design Values in Southwest Indiana (2009-2012)**

Design Values ( $\mu g/m^3$ )	2009	2010	2011	2012	Design Value 2009-2011	Design Value 2010-2012
Evansville - Buena Vista	27.7	30.4	30.0	19.7	29	27
Evansville - Univ. of Evansville	25.5	29.2	28.0	20.8	28	26
Dubois Co. - Jasper	24.7	27.2	27.7	21.7	27	26
Spencer - Dale	24.3	26.7	31.0	19.8	27	26
Henderson Co. - KY	26.2	24.4	26.2	20.2	26	24

Note: The design values for a given period listed in the table above are the average of the background concentration values for those years in the period.

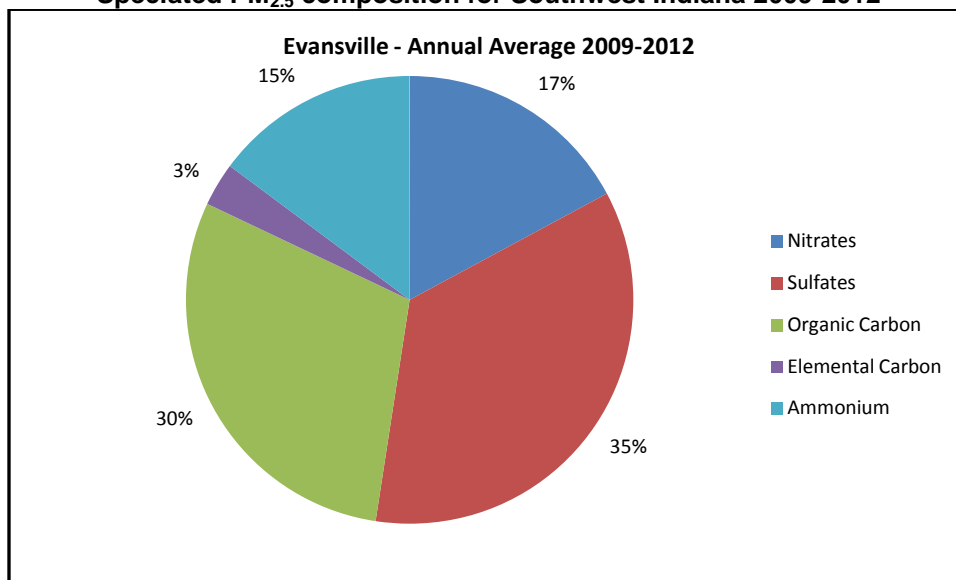
With a difference of  $6 \mu g/m^3$  between the highest 24-hour  $PM_{2.5}$  design value in the southwest

Indiana area and the 24-hour  $PM_{2.5}$  NAAQS of  $35.0 \mu g/m^3$ , the anticipated secondary  $PM_{2.5}$  impacts from MFC is not expected to not cause or contribute impacts to the area that would approach the 24-hour  $PM_{2.5}$  NAAQS.

## 2. Background Speciated Data

Speciated data taken from the Evansville Buena Vista Road monitoring site for 2009 through 2012, found below in Chart 1, show the different species in southwest Indiana's  $PM_{2.5}$  composition. The percentages of the annual average concentrations show sulfates and organic carbon make up a majority of the  $PM_{2.5}$  composition with nitrates, ammonium, and elemental carbon as contributing species to  $PM_{2.5}$  as well. There are a high percentage of sulfates present in the  $PM_{2.5}$  composition, which reflects the influence of coal-burning power plants in the region.

**Chart 1**  
**Speciated  $PM_{2.5}$  composition for Southwest Indiana 2009-2012**



Over a decade of speciated monitoring has shown that in Indiana, all southern sites record higher concentrations of sulfates than those in the central and northern parts of the state. Since  $SO_2$  emissions from MFC are minimal, it will have very little contribution to this key component of  $PM_{2.5}$  composition. Nitrates make up less than one-fifth of the composition of  $PM_{2.5}$  in southwest Indiana; therefore, MFC's impact on secondary  $PM_{2.5}$  formation would be considered small and would not cause or contribute to a 24-hour or annual  $PM_{2.5}$  NAAQS violation.

## 3. Emissions

MFC's proposed emissions are 534.2 tons per year of  $NO_x$  and 7.3 tons per year of  $SO_2$ . A comparison of MFC's  $NO_x$  emissions with the 2011 U.S. EPA's National Emissions Inventory (NEI)  $NO_x$  emissions taken from all point, onroad, nonroad, nonpoint and wildfire emission sources in Posey, Vanderburgh, and Warrick Counties would be 1.9%. MFC's  $SO_2$  emissions are not considered significant but a comparison with the 2011 NEI  $SO_2$  inventory for Posey, Vanderburgh, and Warrick Counties showed MFC would represent 0.03% of all point, onroad, nonroad, nonpoint, and wildfire  $SO_2$  emissions sources within the three-county area.

Another way provide some perspective for these precursor emissions in regard to their  $PM_{2.5}$  formation potential is to examine some earlier work U.S. EPA performed for the 2008  $PM_{2.5}$  New Source Review implementation rule. They established presumptive interpollutant trading ratios for conversion of  $SO_2$  and  $NO_x$  to  $PM_{2.5}$ . These ratios were based upon analyses of nine urban areas across the country. In 2011, U.S. EPA determined this policy could no longer be presumptively applied in all locations because of variability in different areas. However, this analysis is instructive in determining the approximate conversion of these pollutants.

The interpollutant trading ratio assumptions U.S. EPA established in 2008:

Tons $SO_2$ equating to one ton $PM_{2.5}$	40 tons
Tons $NO_x$ equating to one ton $PM_{2.5}$	200 tons.



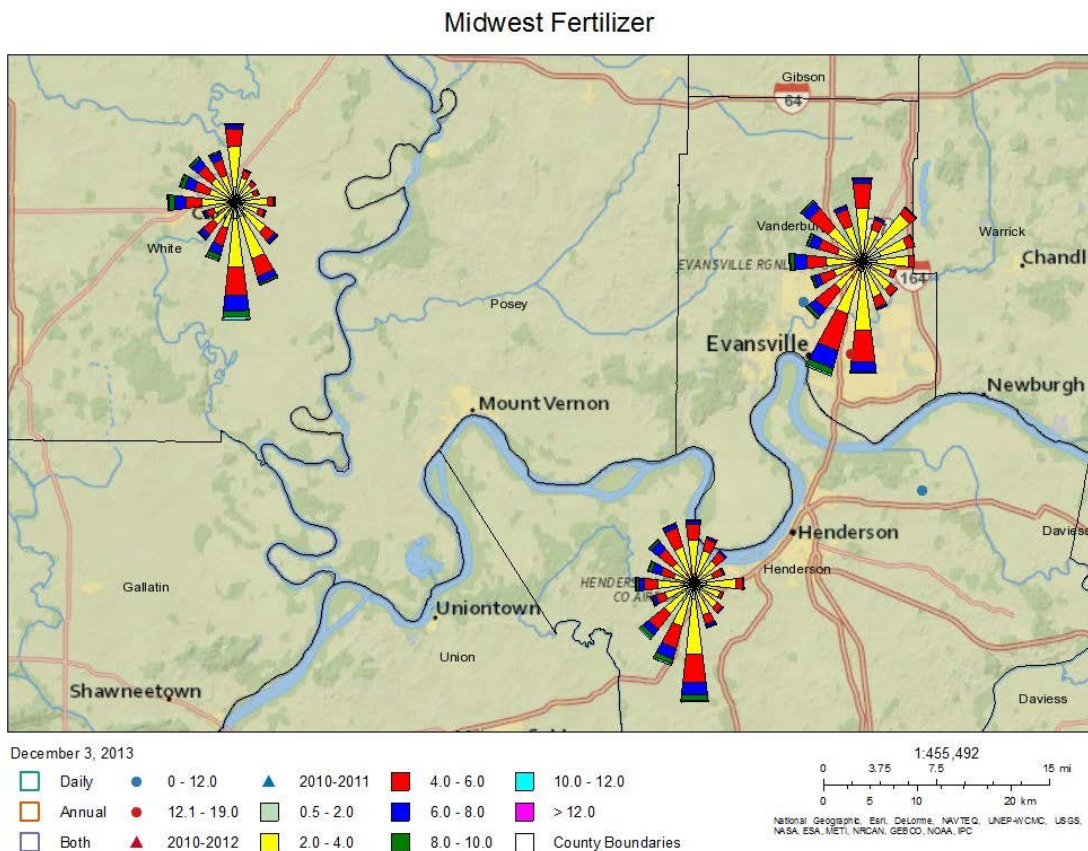
To approximate the impact from this proposed project, 534.2 tons of NO<sub>x</sub> and 7.3 tons of SO<sub>2</sub> would equate to 2.67 and 0.18 tons respectively. This total of 2.85 tons would be an additional 2.7% of the 109.8 tons of PM<sub>2.5</sub> emitted from MFC.

Due to the low percentage of MFC's NO<sub>x</sub> and SO<sub>2</sub> emissions compared to NO<sub>x</sub> and SO<sub>2</sub> emission totals from all three counties, MFC impacts are not anticipated to result in significant secondary PM<sub>2.5</sub> formation that would cause or contribute to a 24-hour or annual PM<sub>2.5</sub> NAAQS violation.

#### 4. Regional Winds/Wind Roses

Figure 3 shows annual wind roses for Vanderburgh County and surrounding airport meteorological stations as taken from U.S. EPA's PM Designations Mapping Tools [http://geoplatform2.epa.gov/PM\\_MAP/index.html](http://geoplatform2.epa.gov/PM_MAP/index.html). These were analyzed and results showed the wind directions were typically from the southwest, south, west, and northwest. MFC would be considered upwind of the Evansville area PM<sub>2.5</sub> monitors and any emissions from MFC could impact these monitors. However, as mentioned above, secondary PM<sub>2.5</sub> impacts are anticipated to be small due to the relatively small NO<sub>x</sub> and SO<sub>2</sub> emissions and formation of secondary PM<sub>2.5</sub> from photochemical reactions would not be expected to occur close to MFC.

**Figure 3**  
**Wind Roses for Evansville and Surrounding Areas**



#### 5. Dispersion Modeling Results

NO<sub>x</sub> and PM<sub>2.5</sub> emissions from MFC exceeded the significant emission rates and additional dispersion modeling was required to determine impacts. SO<sub>2</sub> emissions from MFC fell well below the significant emission rate and were considered insignificant. Since the NO<sub>x</sub> and SO<sub>2</sub> NAAQS

and PSD increments are considered extremely restrictive, a typical source with emissions being below the significant emission rate would likely diminish any secondary pollutant formation. Therefore, SO<sub>2</sub> impacts would unlikely result in a violation of the annual or 24-hour PM<sub>2.5</sub> standards. Dispersion modeling for MFC's NO<sub>x</sub> and PM<sub>2.5</sub> emissions showed that the modeled annual NO<sub>2</sub> concentrations were below Significant Impact Levels (SIL). However, the 1-hour NO<sub>2</sub> modeled concentrations exceeded the SIL and PM<sub>2.5</sub> exceeded its significant emission rate, additional dispersion modeling was required for NO<sub>x</sub> and PM<sub>2.5</sub>. Those modeling results, below in Table 4, showed when the maximum primary 24-hour PM<sub>2.5</sub> concentration was added to the 24-hour PM<sub>2.5</sub> background concentration, the cumulative concentrations from the maximum modeled impacts and background concentrations were well below the 24-hour PM<sub>2.5</sub> NAAQS threshold of 35 µg/m<sup>3</sup>.

**Table 15**  
**National Ambient Air Quality Modeling Analysis for NO<sub>x</sub> and PM<sub>2.5</sub>**

Pollutant	Time Averaging Period	Maximum Impact (µg/m <sup>3</sup> )	Background Concentrations (µg/m <sup>3</sup> )	Total Concentration (µg/m <sup>3</sup> )
NO <sub>2</sub>	1-hour	14.97	67.8	82.77
PM <sub>2.5</sub>	24-hour	2.07	23.30	25.37
PM <sub>2.5</sub>	Annual	0.29	11.3	11.59

In the Emissions section above, it was approximated that the precursor emissions would add 2.7% to PM<sub>2.5</sub> totals. Adding an additional 2.7% to the 24-hour and annual impacts of PM<sub>2.5</sub> would result in an additional 0.056 µg/m<sup>3</sup> and 0.0078 µg/m<sup>3</sup> respectively to the Total Concentrations in the table above.

The locations for the maximum modeled primary PM<sub>2.5</sub> concentrations would occur near the fence line, or areas very close to the MFC property. Maximum secondary PM<sub>2.5</sub> concentrations would be expected to occur further from the emission source; typically these reactions take place over tens to hundreds of kilometers downwind. Secondary PM<sub>2.5</sub> concentrations would be anticipated to be low at the maximum modeled primary PM<sub>2.5</sub> concentrations while modeled primary PM<sub>2.5</sub> concentrations would be anticipated to be much lower at the maximum secondary PM<sub>2.5</sub> concentrations locations, assumed to occur further away from MFC. For these reasons, MFC's emissions are not anticipated to result in secondary PM<sub>2.5</sub> impacts that would cause or contribute to a 24-hour or annual PM<sub>2.5</sub> NAAQS violation.

### **Summary of Annual and 24-Hour PM<sub>2.5</sub> Secondary Impacts**

Midwest Fertilizer Company's SO<sub>2</sub> and NO<sub>x</sub> emissions were analyzed to determine what PM<sub>2.5</sub> impacts may occur as a result of its precursor emissions forming secondary PM<sub>2.5</sub>. When MFC's secondary pollutant emissions and impacts were compared with the primary PM<sub>2.5</sub> background concentrations, 2011 NEI county emission inventories, and primary PM<sub>2.5</sub> dispersion modeling impact on the southwest Indiana air shed and northwest Kentucky PM<sub>2.5</sub> monitors, it was demonstrated that impacts are anticipated to be minimal. This assessment concluded that MFC will not have an effect on the annual and 24-hour PM<sub>2.5</sub> attainment status of Posey County or any surrounding counties in the area.

## **Part G - Summary of Air Quality Analysis**

Posey County is designated as attainment for all criteria pollutants.  $PM_{10}$ ,  $NO_2$ , CO,  $PM_{2.5}$ , and VOC emission rates associated with the proposed facility exceeded the respective significant emission rates. Modeling results taken from AERMOD model showed that CO,  $PM_{10}$ , annual  $NO_2$ , and annual  $PM_{2.5}$  impacts were less than significance levels. NAAQS modeling showed exceedances of the 1-hour  $NO_2$ , and the annual and 24-hour  $PM_{2.5}$  standards, but those were not adversely impacted by Midwest. A secondary analysis for  $PM_{2.5}$  and ozone showed minimal impact. Midwest did trigger preconstruction monitoring threshold level for  $NO_2$  and  $PM_{2.5}$ . Midwest's impact was below 80% of the available  $PM_{10}$  and  $PM_{2.5}$  increment. The nearest Class I area is Mammoth Cave National Park in Kentucky 165 kilometers away from the source, and will not affect visibility. An additional impact analysis was required but the operation of the proposed facility will have no significant impact.



## INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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**Michael R. Pence**  
*Governor*

**Thomas W. Easterly**  
*Commissioner*

### SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Michael Chorlton  
Midwest Fertilizer Corporation  
PO Box 3016  
Indianapolis, In 46206

DATE: June 4, 2014

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

SUBJECT: Final Decision  
PSD/New Source Construction and Title V Operating Permit  
129-33576-00059

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:  
Tom Rarick, Environmental Resources Management (ERM)  
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](mailto:jbrush@idem.IN.gov).

Final Applicant Cover letter.dot 6/13/2013



## INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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**Michael R. Pence**  
*Governor*

**Thomas W. Easterly**  
*Commissioner*

June 4, 2014

TO: Alexandrian Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**


**Applicant Name: Midwest Fertilizer Corporation**  
**Permit Number: 129-33576-00059**

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 6/13/2013


# Mail Code 61-53

IDEM Staff	VHAUN 6/4/2014 Midwest Fertilizer Corporation 129-33576-00059 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:  <b>CERTIFICATE OF MAILING ONLY</b>	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handling 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		Michael Chorlton Midwest Fertilizer Corporation PO Box 3016 Indianapolis IN 46206 (Source CAATS)			CONFIRMED DELIVERY						
2		Posey County Commissioners County Courthouse, 126 E. 3rd Street Mount Vernon IN 47620 (Local Official)									
3		Posey County Health Department 126 E. 3rd St, Coliseum Bldg Mount Vernon IN 47620-1811 (Health Department)									
4		Mount Vernon City Council and Mayors Office 520 Main Street Mount Vernon IN 47620 (Local Official)									
5		Dr. Jeff Seyler Univ. of So Ind., 8600 Univ. Blvd. Evansville IN 47712 (Affected Party)									
6		Mr. Don Mottley Save Our Rivers 6222 Yankeetown Hwy Boonville IN 47601 (Affected Party)									
7		Alexandrian Public Library 115 West 5th Mt. Vernon IN 47620 (Library)									
8		Mr. Mark Wilson Evansville Courier & Press P.O. Box 268 Evansville IN 47702-0268 (Affected Party)									
9		Joanne Alexandrovich Vanderburgh County Health Dept. 420 Mulberry ST. Evansville IN 47713 (Affected Party)									
10		Mrs. Connie Parkinson 510 Western Hills Dr. Mt. Vernon IN 47620 (Affected Party)									
11		Tom Rarick Environmental Resources Management (ERM) 11350 N Meridian Suite 320 Carmel IN 46032 (Consultant)									
12		Robert Hess c/o Mellon Corporation 830 Post Road East, Suite 105 Westport CT 06880 (Affected Party)									
13		Juanita Burton 7911 W. Franklin Road Evansville IN 47712 (Affected Party)									
14		State of Indiana 3650 S US Hwy 41 Vincennes IN 47759 (Affected Party)									
15		Tom Garrett 5313 Old Booneville Hwy Evansville IN 47715 (Affected Party)									

Total number of pieces Listed by Sender  <b>14</b>	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 <b>Domestic Mail Manual R900, S913, and S921</b> for limitations of coverage on inured and COD mail. See <b>International Mail Manual</b> 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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											Remarks
1		David Boggs 216 Western Hills Dr Mt Vernon IN 47620 (Affected Party)									
2		John Blair 800 Adams Ave Evansville IN 47713 (Affected Party)									
3		Lucy A Bottomley 2525 Serenity Place Evansville IN 47720 (Affected Party)									
4		Agrigenetics, Inc. 2030 Dow Center/317 Midland MI 48674 (Affected Party)									
5		Allyn Land Company, LP 5101 Lamont Road Mt Vernon IN 47620 (Affected Party)									
6		Emerald Restaurant Repair, Inc. 698 E Heinberg Suite 105 Pensacola FL 35202 (Affected Party)									
7		Howmull Properties, LLC 15 E Main Street Ste 300 Carmel IN 46032 (Affected Party)									
8		Ports of Indiana 150 W Market Suite 100 Indianapolis IN 46204 (Affected Party)									
9		Mt. Vernon Coal Transfer 2720 N Hemlock Ct, Ste B Broken Arrow OK 74012 (Affected Party)									
10		Esther Uebelhack 2800 Lower Mt Vernon Road Mt. Vernon IN 47620 (Affected Party)									
11		James F Davis 608 East Grant Street Mt Vernon IN 47620 (Affected Party)									
12		Thomas Guggenheim 7160 Upton Rd Mt Vernon IN 47620 (Affected Party)									
13		Ed Adams 210 Dogwood Pl Mt Vernon IN 47620 (Affected Party)									
14		Thomas Sommerfield 2700 Blackburn Rd Mt Vernon In 47620 (Affected Party)									
15		Mark Beard 307 N 4th Ave Evansville In 47710 (Affected Party)									

Total number of pieces Listed by Sender  <b>15</b>	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 <b>Domestic Mail Manual R900, S913, and S921</b> for limitations of coverage on inured and COD mail. See <b>International Mail Manual</b> 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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											Remarks
1		Steve Wilson 951 N Park Dr Evansville IN 47710 (Affected Party)									
2		Gil Barchet 9020 Fischer Rd Evansville IN 47720 (Affected Party)									
3		Brian Hermann 7636 Sauerkraut Ln S Mt Vernon IN 47620 (Affected Party)									
4		John Blanton 530 Mill St Mt Vernon IN 47620 (Affected Party)									
5		George Postlethweight 5901 Hartman Rd Mt Vernon IN 47620 (Affected Party)									
6		Steve Beegle 6355 Woodland Springs Dr Newburgh IN 47630 (Affected Party)									
7		Sarah Helming 123 NW 4th St, Ste 417 Evansville IN 47708 (Affected Party)									
8		Don Mattingly 10535 Downen Rd Wadesville In 47638 (Affected Party)									
9		Judy Heberer 7536 Sauerkraut Mt Vernon IN 47620 (Affected Party)									
10		Greg Bussell 2212 Tanglewood Dr Mt Vernon IN 47620 (Affected Party)									
11		Rodney Cox 1907 Holler Rd Mt Vernon IN 47620 (Affected Party)									
12		Lee Reeves 1800 Green Briar Mt Vernon IN 47620 (Affected Party)									
13		Robert Schirmer 432 Locust St Mt Vernon IN 47620 (Affected Party)									
14		Anthony Gross 7575 S Sauerkraut Ln Mt Vernon IN 47620 (Affected Party)									
15		Christine Dunn Henderson 10131 Bahamas Circle Fishers IN 46037 (Affected Party)									

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											Remarks
1		Mark Bryant Valley Watch Inc. 800 Adams Avenue Evansville IN 47713 (Affected Party)									
2		Michael J Zupan 2811 Graddy Road Mount Vernon IN 47620 (Affected Party)									
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Total number of pieces Listed by Sender  <b>2</b>	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 <b>Domestic Mail Manual R900, S913, and S921</b> for limitations of coverage on inured and COD mail. See <b>International Mail Manual</b> 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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