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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: July 31, 2013

RE: Central Indiana Ethanol, LLC / 053-32519-00062

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

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

Enclosures
FNPER.dot 6/13/13

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

July 31, 2013

Mr. Norm Currey
Central Indiana Ethanol, LLC
2955 West Delphi Pike
Marion, IN 46952

Re: 053-32519-00062
Significant Source Modification to
Part 70 No.: T053-32070-00062

Dear Mr. Currey:

Central Indiana Ethanol, LLC was issued a FESOP Renewal on September 27, 2010 for a stationary ethanol production plant, capable of producing both dried distillers grain solubles (DDGS) and wet distillers grain solubles (WDGS). A letter requesting changes to this permit was received on November 15, 2012. Pursuant to 326 IAC 2-7-10.5, the following emission units are approved for construction at the source:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(2) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.

Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(3) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.

Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

(4) Two (2) natural gas fired boilers, identified as Boiler #1 (EU093) and Boiler #2 (EU094), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU093 and EU094 are affected facilities.

(o) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(p) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(c) Forced and induced draft cooling tower systems not regulated under a NESHAP, consisting of:

(2) One (1) four cell cooling tower, identified as F004, with a circulation rate of 21,000 gallons per minute.

The following construction conditions are applicable to the proposed project:

General Construction Conditions

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

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

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

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

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

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

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

For your convenience, the entire Part 70 Operating Permit as modified will be provided at issuance.

This decision is subject to the Indiana Administrative Orders and Procedures Act – IC 4-21.5-3-5. If you have any questions on this matter, please contact Julie Alexander, OAQ, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or call at (800) 451-6027, and ask for Julie Alexander or extension 3-1782, or dial (317) 233-1782.

Sincerely,

Jenny Acker, Section Chief
Permits Branch
Office of Air Quality

Attachments
JA/jla
cc: File - Grant County
U.S. EPA, Region V
Grant County Health Department
Compliance and Enforcement Branch

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

Significant Source Modification to a Part 70 Source
OFFICE OF AIR QUALITY

Central Indiana Ethanol, LLC
2955 West Delphi Pike
Marion, Indiana 46952

(herein known as the Permittee) is hereby authorized to construct subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17. This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-7-10.5, applicable to those conditions.

Significant Source Modification No.: 053-32519-00062	
Issued by: Jenny Acker, Section Chief Permits Branch Office of Air Quality	Issuance Date: July 31, 2013

TABLE OF CONTENTS

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, A.3, and A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)] [326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary ethanol production plant.

Source Address:	2955 West Delphi Pike, Marion, Indiana 46952
General Source Phone Number:	(765) 384 4001
SIC Code:	2869
County Location:	Grant
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Minor Source, under PSD, with Greenhouse Gases above 100,000 tons per year Minor Source, under Section 112 of the Clean Air Act Not 1 of 28 Source Categories

A.2 Part 70 Source Definition [326 IAC 2-7-1(22)]

This stationary ethanol production plant consists of two (2) plants:

(a) Central Indiana Ethanol, LLC is located at 2955 West Delphi Pike, Marion, Indiana; and

(b) EPCO Carbon Dioxide Products is located at 2975 West Delphi Pike, Marion, Indiana.

However, these plants are located on one or more contiguous properties, have the same two digit SIC code in addition to a support relationship, and are under common control. Therefore, they are considered one (1) major source, as defined by 326 IAC 2-7-1(22).

A.3 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:

(e) One (1) receiving and transfer system, approved for construction in 2011, consisting of:

(1) One (1) unloading area, consisting of:

(C) One (1) fork truck unloading area, identified as EU075, with a maximum capacity of 25 tons of material per hour, approved in 2013 for modification, with particulate emissions vented through either of the following:

(i) One (1) manual conveyance system, controlled by baghouse CE016, exhausting to stack EP016.

(ii) One (1) pneumatic conveyance system, controlled by baghouse CE022, exhausting to stack EP022.

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(2) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.

Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(3) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.

Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

(4) Two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU081 and EU082 are affected facilities.

(o) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(p) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

A.4 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, as defined in 326 IAC 2-7-1(21):

(c) Forced and induced draft cooling tower systems not regulated under a NESHAP, consisting of:

(2) One (1) four cell cooling tower, identified as F004, with a circulation rate of 21,000 gallons per minute.

A.5 Part 70 Permit Applicability [326 IAC 2-7-2]

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

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

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

SECTION B GENERAL CONDITIONS

B.1 Advanced Source Modification Approval [326 IAC 2-7-5(15)] [326 IAC 2-7-10.5]

Pursuant to 326 IAC 2-7-10.5(f)(3), the emission units specified in Section A.3 are hereby approved for construction.

B.2 Permit No Defense [IC 13-11 through 13-20] [IC 13-22 through 13-25]

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

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

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

B.4 Revocation of Permits [326 IAC 2-1.1-9(5)] [326 IAC 2-7-10.5(j)]

Pursuant to 326 IAC 2-7-10.5(j), construction must commence within eighteen (18) months of the issuance of this approval.

B.5 Modification to Construction Conditions [326 IAC 2]

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS – Grain / DDGS Receiving & Handling

Emissions Unit Description [326 IAC 2-7-5(14)]:

(e) One (1) receiving and transfer system, approved for construction in 2011, consisting of:

(1) One (1) unloading area, consisting of:

(C) One (1) fork truck unloading area, identified as EU075, with a maximum capacity of 25 tons of material per hour, approved in 2013 for modification, with particulate emissions vented through either of the following:

(i) One (1) manual conveyance system, controlled by baghouse CE016, exhausting to stack EP016.

(ii) One (1) pneumatic conveyance system, controlled by baghouse CE022, exhausting to stack EP022.

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

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

D.1.1 PSD Minor Limits for PM, PM_{10}, and $PM_{2.5}$ [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (PSD) not applicable, PM, PM_{10}, and $PM_{2.5}$ emissions from the following units shall not exceed the emission limits listed in the table below:

Unit ID	Stack ID	Unit Description	Control ID	PM Emission Limit (lb/hr)	PM_{10} Emission Limit (lb/hr)	$PM_{2.5}$ Emission Limit (lb/hr)
EU075	EP016	Fork Truck Unloading Area	CE016	0.64	0.64	0.64

Note: Emission limits are combined lb/hr limits for all emission units exhausting out of each stack.

Compliance with these PM, PM_{10}, and $PM_{2.5}$ limits, combined with the potential to emit PM, PM_{10}, and $PM_{2.5}$ from other emission units at the source, shall limit the PM, PM_{10}, and $PM_{2.5}$ emissions from the entire source to less than 250 tons per twelve (12) consecutive month period, each, and render 326 IAC 2-2 (PSD) not applicable.

D.1.2 Particulate Emission Limitations [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2, particulate emissions from each of following operations shall not exceed the pound per hour limit listed in the table below:

Unit ID	Unit Description	Control ID	Max. Throughput Rate (tons/hr)	Particulate Emission Limit (lb/hr)
EU075	Fork Truck Unloading Area	CE016	25	35.43

The pounds per hour limitations were calculated using the following equations:

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

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

D.1.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS – Non-Fuel Grade Ethanol

Emissions Unit Description [326 IAC 2-7-5(14)]:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(2) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.

Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(3) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.

Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

(4) Two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU081 and EU082 are affected facilities.

(o) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(p) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

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

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

D.2.1 Minor Limits for VOC, CO, NO_x, and HAP [326 IAC 2-2] [326 IAC 2-4.1] [Clean Air Act, Section 112(a)(1) and (a)(2)]

In order to render the requirements of 326 IAC 2-2 (PSD) and 326 IAC 2-4.1 (MACT) not applicable, the Permittee shall comply with the following emission limits for the loading skids EU083 and EU084:

(a) The potential emissions of cumulative HAPs shall be limited to no more than 3.85 tons per year from Tanks T013 through T017 and shall be limited to any single HAP or combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl isobutyl ketone, and toluene.

(b) The total combined non-fuel grade ethanol load-out from loading skids EU083 and EU084 shall not exceed 60,000,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) CO emissions from flare CE019, controlling ethanol loading skids EU083 and EU084, shall not exceed 0.129 lb/kgal.

(d) NO_x emissions from flare CE019, controlling ethanol loading skids EU083 and EU084, shall not exceed 0.077 lb/kgal.

Compliance with these VOC, CO, and NO_x limits, combined with the potential to emit VOC, CO, and NO_x from other emission units at the source, shall limit the VOC, CO, and NO_x emissions from the entire source to less than 250 tons per twelve (12) consecutive month period and render 326 IAC 2-2 (PSD) not applicable.

Compliance with these HAP limits, combined with the potential to emit HAP from other emission units at the source, shall limit the HAP emissions from the entire source to less than 10 tons per twelve (12) consecutive month period for a single HAP and less than 25 tons per twelve (12) consecutive month period for total HAPs and render 326 IAC 2-4.1 (MACT) not applicable.

D.2.2 Particulate Emissions [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), particulate emissions from the 48.16 MMBtu/hr Boiler #1 (EU081) and Boiler #2 (EU082) shall be limited to 0.26 pounds per MMBtu heat input, each.

The limit was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}} = \frac{1.09}{(231.32)^{0.26}} = 0.26 \text{ lb/MMBtu}$$

Where: Pt = emission rate limit (lb/MMBtu)
Q = total source heat input capacity (MMBtu/hr)

D.2.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.2.4 VOC and HAP Control

In order to comply with Condition D.7.1 for VOC and HAP control:

(a) Enclosed flare CE019 shall be in operation and control emissions from the non-fuel grade ethanol loading skids (EU083 and EU084) at all times when these skids are in operation.

(b) The ethanol loading skids (EU083 and EU084) shall utilize submerged loading method.

(c) The railcars and trucks shall not use vapor balance services.

D.2.5 VOC and HAP

In order to determine compliance with the VOC and HAP emissions limits in Condition D.7.1(a), the VOC and HAP emissions from the tank storage and tank filling of Tanks T013 through T017 shall be calculated using USEPA's TANKS program (version 4.0 or its updates).

D.2.6 Testing Requirements [326 IAC 2-1.1-11]

Not later than 180 days after the startup of the closed-loop distillation process, the Permittee shall perform VOC (including emission rate, capture efficiency, and destruction efficiency), CO, and NO_x testing of enclosed flare CE019 utilizing methods as approved by the Commissioner 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.

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

D.2.7 Flare Pilot Flame

In order to comply with Condition D.7.1, the Permittee shall monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame when ethanol loading skids EU083 and/or EU084 are in operation.

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

D.2.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.7.1(b), the Permittee shall maintain monthly records of the total amount of non-fuel grade ethanol loaded out from loading racks EU083 and EU084.

(b) To document the compliance status with Condition D.7.6, the Permittee shall maintain records of temperature or other parameters sufficient to demonstrate the presence of a pilot flame when loading skids EU083 and/or EU084 are in operation.

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

D.2.9 Reporting Requirements

A quarterly report of the non-fuel grade ethanol loading to document the compliance status with Condition D.7.1(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C – General Reporting contains the Permittee's obligations 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 by 326 IAC 2-7-1(35).

SECTION E.1 FACILITY OPERATION CONDITIONS - 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984

Facility Description [326 IAC 2-7-5(14)]:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(2) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.
Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(3) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.
Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

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

New Source Performance Standards (NSPS) Requirements

E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR 60, Subpart A]

(a) The Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, for the Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984, as specified in 40 CFR 60, Subpart Kb in accordance with the schedule in 40 CFR 60, Subpart Kb.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Ave.
MC61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.1.2 Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984 [40 CFR 60, Subpart Kb] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Kb (included as Attachment D) which are incorporated by reference as 326 IAC 12 for the Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced after July 23, 1984:

(a) 40 CFR 60.110b (a), (b), (d)(2), (d)(3), (d)(7), (d)(8), (e)(1)(i), (e)(2), (e)(3);
(b) 40 CFR 60.111b;
(c) 40 CFR 60.112b(a)(1);
(d) 40 CFR 60.113b(a);
(e) 40 CFR 60.115b(a);
(f) 40 CFR 60.116b(a), (b), (c), (e) ; and
(g) 40 CFR 60.117b.

SECTION E.2 FACILITY OPERATION CONDITIONS - 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

Facility Description [326 IAC 2-7-5(14)]:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(o) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(p) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

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

New Source Performance Standards (NSPS) Requirements

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

(a) The Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, for the sources of equipment leaks of VOC, as specified in 40 CFR 60, Subpart VVa in accordance with the schedule in 40 CFR 60, Subpart VVa.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Ave.
MC61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.2.2 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 [40 CFR 60, Subpart VVa] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart VVa (included as Attachment C) which are incorporated by reference as 326 IAC 12 for the sources of equipment leaks of VOC:

(a) 40 CFR 60.480a;
(b) 40 CFR 60.481a;
(c) 40 CFR 60.482-1a;
(d) 40 CFR 60.482-2a;
(e) 40 CFR 60.482-3a;
(f) 40 CFR 60.482-4a;
(g) 40 CFR 60.482-5a;
(h) 40 CFR 60.482-6a;
(i) 40 CFR 60.482-7a;
(j) 40 CFR 60.482-8a;
(k) 40 CFR 60.482-9a;
(l) 40 CFR 60.482-10a;
(m) 40 CFR 60.482-11a;
(n) 40 CFR 60.483-1a;
(o) 40 CFR 60.483-2a;
(p) 40 CFR 60.484a;
(q) 40 CFR 60.485a;
(r) 40 CFR 60.486a;
(s) 40 CFR 60.487a;
(t) 40 CFR 60.488a; and
(u) 40 CFR 60.489a.

SECTION E.3 FACILITY OPERATION CONDITIONS - 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Facility Description [326 IAC 2-7-5(14)]:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(4) Two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU081 and EU082 are affected facilities.

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

New Source Performance Standards (NSPS) Requirements

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

(a) The Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12, for the Small Industrial-Commercial-Institutional Steam Generating Units, as specified in 40 CFR 60, Subpart Dc in accordance with the schedule in 40 CFR 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Ave.
MC61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.3.2 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc] [326 IAC 12]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment G) which are incorporated by reference as 326 IAC 12 for the Small Industrial-Commercial-Institutional Steam Generating Units:

(a) 40 CFR 60.40c(a), (b), (c), (d);
(b) 40 CFR 60.41c; and
(c) 40 CFR 60.48c(a), (f)(4), (g), (i), (j).

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

Source Name: Central Indiana Ethanol, LLC
Source Address: 2955 West Delphi Pike, Marion, Indiana 46952

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: Central Indiana Ethanol, LLC
Source Address: 2955 West Delphi Pike, Marion, Indiana 46952

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12)

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

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

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

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

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

Form Completed by:______________________________

Title / Position: __________________________________

Date:____

Phone: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Central Indiana Ethanol, LLC
Source Address: 2955 West Delphi Pike, Marion, Indiana 46952
Facility: Loading Racks (EU083 and EU084)
Parameter: Total combined non-fuel grade ethanol loadout rate
Limit: The total combined non-fuel grade ethanol load-out from loading skids EU083 and EU084 shall not exceed 60,000,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

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: Central Indiana Ethanol, LLC
Source Address: 2955 West Delphi Pike, Marion, Indiana 46952

Months: _________ to ___________ Year: ____________

Page 1 of 2

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:	

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

Form Completed by:______________________________

Title / Position: _________________________________

Date:____

Phone: ____

Indiana Department of Environmental Management
Office of Air Quality

Attachment C

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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:

	Equivalent monitoring frequency time in use		
Operating time (percent of hours during year)	**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_2O 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_2O 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^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(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^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(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 nonrepairable, 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 D

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

§ 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

(1) Vessels at coke oven by-product plants.

(2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

(3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.

(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.

(5) Vessels located at bulk gasoline plants.

(6) Storage vessels located at gasoline service stations.

(7) Vessels used to store beverage alcohol.

(8) Vessels subject to subpart GGGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Fill means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

Gasoline service station means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

Petroleum means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

Petroleum liquids means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see §60.17).

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

(1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;

(2) Subsurface caverns or porous rock reservoirs; or

(3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

§ 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4) (i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212 Cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113b(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

§ 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement.

(b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

§ 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(1) and §60.113b(a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of §60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

§ 60.117b Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

Indiana Department of Environmental Management
Office of Air Quality

Attachment G

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility 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.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c 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 an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum 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 during a period of 12 consecutive calendar months.

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 derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product 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 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 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_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that 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 reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(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 a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

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.

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 stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

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 (LP) 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 oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as 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 a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit 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.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2 .

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the 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 combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the 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:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal 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 in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected 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 under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator 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 and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, 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 if the affected facility combusts only coal, or combusts coal with 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 with other fuels, 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.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) 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, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater 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, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(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, whichever date comes first, 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 heat input capacity of 8.7 MW (30 MMBtu/h) or greater 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) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. 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.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c 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 affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{ho} o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{ao} o). The E_{ho} o is computed using the following formula:

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

Where:

E_{ho} o = Adjusted E_{ho} , ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential SO_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$ o) is computed from E_{ao} o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai} o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

Where:

$\%R_g$ o = Adjusted $\%R_g$, in percent;

E_{ao} o = Adjusted E_{ao} , ng/J (lb/MMBtu); and

E_{ai} o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai} o, an adjusted hourly SO_2 inlet rate (E_{hi} o) is used. The E_{hi} o is computed using the following formula:

$$E_{hi} o = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

E_{hi} o = Adjusted E_{hi} , ng/J (lb/MMBtu);

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) 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 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected 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 of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be 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.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) 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 install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 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 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 (d) 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 paragraph (c)(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 (c)(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 (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 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/*) 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.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) 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) 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 subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 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 (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit 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.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the 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 in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that 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 § 60.43c 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 § 60.45c(a)(8).

(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) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) 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 § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) 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.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each 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.

(3) 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.

(4) You must record the CO measurements and calculations performed according to paragraph (e) 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.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit 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. 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 § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of 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 § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device 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 § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(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 (c)(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 (c)(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

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions 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 the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

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

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

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-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.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a
Part 70 Significant Source Modification

Source Background and Description

Source Name:	Central Indiana Ethanol, LLC
Source Location:	2955 West Delphi Pike, Marion, IN 46952
County:	Grant
SIC Code:	2869 (Industrial Organic Chemicals)
Significant Source Modification No.:	053-32519-00062
FESOP No.:	F053-29180-00062
Permit Reviewer:	John Haney/Julie Alexander

Existing Approvals

The source was issued its FESOP Renewal No. F053-29180-00062 on September 27, 2010. The source has since received the following approvals:

Permit Type	Permit Number	Issuance Date
Minor Permit Revision	053-30294-00062	April 13, 2011
Administrative Amendment	053-30470-00062	May 27, 2011
Interim Significant Source Modification	053-32519I-00062	January 18, 2013
Minor Source Modification	053-32842-00062	February 26, 2013

The source submitted an application relating to the transition of the source's operating permit from a Federally Enforceable State Operating Permit (FESOP) to a Part 70 Operating Permit on June 29, 2012.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

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

County Attainment Status

The source is located in Grant County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Attainment effective December 29, 2005, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for $PM_{2.5}$.	

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

(b) $PM_{2.5}$
Grant County has been classified as attainment for $PM_{2.5}$. On May 8, 2008, U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011, the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011. Therefore, direct $PM_{2.5}$, NO_X, and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants
Grant County has been classified as attainment or unclassifiable in Indiana for all regulated pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this type of operation is not one of the twenty-eight (28) listed source categories under 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7, and there is no applicable New Source Performance Standard that was in effect on August 7, 1980, fugitive emissions are not counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Unrestricted Potential Emissions

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	Emissions (ton/yr)
PM	Great than 100, Less than 250
PM10	Less than 100
PM2.5	Less than 100
SO2	Less than 100
VOC	Less than 100
CO	Less than 100
NOX	Less than 100
GHGs as CO2e	Greater than 100,000
Single HAP (acetaldehyde)	Less than 10
Total HAPs	Less than 25

(a) This existing source is not a major stationary source, under PSD (326 IAC 2-2), because no regulated pollutant is emitted at a rate of two hundred fifty (250) tons per year or more and it is not one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

On July 20, 2011 U.S. EPA issued a deferral of Biogenic CO2 emissions from PSD and Title V. Therefore, these CO2 emissions were not included in the listed GHG emissions.

(c) This existing source is not a major source of HAPs, as defined in 40 CFR 63.2, because HAPs emissions are less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).

Proposed Modification
Non-fuel Grade Ethanol Distillation Process

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Central Indiana Ethanol, LLC on November 15, 2012, relating to the addition of a proposed non-fuel grade ethanol distillation process. On January 1, 2013, IDEM issued an interim significant source modification for this modification. The following is a list of the proposed emission units and pollution control devices:

(n) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(2) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.

Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(3) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.

Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

(4) Two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU081 and EU082 are affected facilities.

(o) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(p) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

Insignificant Activities

(c) Forced and induced draft cooling tower systems not regulated under a NESHAP, consisting of:

(2) One (1) four cell cooling tower, identified as F004, with a circulation rate of 21,000 gallons per minute.

Stack Summary

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (^{0}F)
EP019	Loadout Skid Flare (CE019)	20	2.50	6,400	900
EP020	Boiler #1 (EU081)	38	2.67	TBD	TBD
EP021	Boiler #2 (EU082)	38	2.67	TBD	TBD

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Increase in PTE Before Controls of the Modification	
Pollutant	Potential To Emit (tons/yr)
PM	0.79
PM_{10}	3.14
$PM_{2.5}$	3.14
SO_2	0.25
VOC	65.81
CO	57.34
NO_x	54.85
GHGs as CO_2e	55,119
Single Worst HAP	Less than 10
Total HAPs	Less than 25

Appendix A of this TSD reflects the unrestricted potential emissions of the modification.

This source modification is subject to 326 IAC 2-7-10.5(g)(4) because the potential to emit nitrogen oxides (NO_x) and VOC is greater than twenty-five (25) tons per year before control, each. On January 1, 2013, IDEM issued an interim significant source modification for this modification.

The modification is subject to the requirements of 326 IAC 2-7-12(d), for a significant permit modification because the modification requires significant changes in existing monitoring Part 70 permit terms and conditions. Specifically, the modification incorporates applicable portions of the following New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) under Title I of the Clean Air Act (CAA):

- NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc);

- NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984 (40 CFR 60, Subpart Kb);

- NSPS for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (40 CFR 60, Subpart VVa); and

- NESHAP for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC).

However, because the source is transitioning its operating permit from a Federally Enforceable State Operating Permit (FESOP) to a Part 70 Operating Permit, the issuance of the Part 70 Operating Permit itself will grant the source the appropriate operating approval for the proposed modification. Therefore, there will be no need to issue a distinct significant permit modification for this proposed modification.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 source modification, 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 (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	NO_x	VOC	CO	GHGs	Total HAPs	Worst Single HAP(1)
Boiler #1 and Boiler #2	0.79	3.14	3.14	0.25	41.36	2.27	34.74	49,935	0.78	0.74
Non-Fuel Grade Ethanol Loadout and Flare	negl.	negl.	negl.	negl.	2.31	0.22	3.87	5,184	0.08	0.09
Total for Modification	**0.79**	**3.14**	**3.14**	**0.25**	**43.67**	**2.49**	**38.61**	**55,119**	**0.86**	**0.83**
PSD Major Source Thresholds	250	250	250	250	250	250	250	N/A	N/A	N/A
Significant Level	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75,000 CO_2e	N/A	N/A

negl. = negligible
*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), not particulate matter (PM), is considered as a "regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.
(1) Worst Single HAP for the project is hexane.

This modification to an existing minor stationary source is not major because the emissions increase is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

On July 20, 2011, U.S. EPA issued a deferral of biogenic CO_2 emissions from PSD and Title V. Therefore, these CO_2 emissions were not included in the listed GHG emissions.

Proposed Modification
Fork Truck Unloading Area (EU075)

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Central Indiana Ethanol, LLC on February 19, 2013, relating to the addition of a pneumatic conveyance system for the existing fork truck unloading area (EU075). On February 26, 2013, IDEM issued a minor source modification for this modification. The following is a list of the modified emission unit and pollution control device:

(e) One (1) receiving and transfer system, approved for construction in 2011, consisting of:

(1) One (1) unloading area, consisting of:

(C) One (1) fork truck unloading area, identified as EU075, with a maximum capacity of 25 tons of material per hour, approved in 2013 for modification, with particulate emissions vented through either of the following:

(i) One (1) manual conveyance system, controlled by baghouse CE016, exhausting to stack EP016.

(ii) One (1) pneumatic conveyance system, controlled by baghouse CE022, exhausting to stack EP022.

Stack Summary

Stack ID	Operation	Height (ft)	Diameter (ft)	Flow Rate (acfm)	Temperature (^{0}F)
EP022	Fork Truck Unloading Area (EU075) - Pneumatic	29.5	3.6	22,500	70

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency.”

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

PTE Change of the Modified Process			
Pollutant	**PTE Before Modification** (tons/yr)	**PTE After Modification** (tons/yr)	**Increase from Modification** (tons/yr)
PM	2.77	27.69	24.92
PM_{10}	2.77	27.69	24.92
$PM_{2.5}$	2.77	27.69	24.92

PTE Change of the Modified Process			
Pollutant	**PTE Before Modification** (tons/yr)	**PTE After Modification** (tons/yr)	**Increase from Modification** (tons/yr)
SO_2	-	-	-
VOC	-	-	-
CO	-	-	-
NO_X	-	-	-
HAPs	-	-	-

This source modification is subject to 326 IAC 2-7-10.5(d)(3)(A) because the potential to emit particulate matter (PM) and particulate matter less than ten microns (PM_{10}) is each greater than five (5) tons per year and less than twenty-five (25) tons per year before control.

On February 26, 2013, IDEM issued a minor source modification for this modification. Additionally, this modification will be incorporated into the Part 70 Operating Permit through a minor permit modification issued pursuant to 326 IAC 2-7-12(b)(1) because the modification:

(a) Does not violate any applicable requirement;

(b) Does not involve significant changes to existing monitoring, reporting, or record keeping requirements in the Part 70 permit;

(c) Does not require or change a:

  (1) case-by-case determination of an emission limitation or other standard;

  (2) source specific determination for temporary sources of ambient impacts; or

  (3) visibility or increment analysis;

(d) Does not seek to establish or change a Part 70 permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. The terms and conditions include the following:

  (1) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the CAA; or

  (2) An alternative emissions limit approved under regulations promulgated under Section 112(i)(5) of the CAA;

(e) Is not a modification under any provision of Title I of the CAA;

(f) Is not the addition of a clean unit that was automatically designated as described in 326 IAC 2-2.2-1 or 326 IAC 2-3.2-1;

(g) Is not the addition of a listed PCP as defined in 326 IAC 2-2-1(ll) or 326 IAC 2-3-1(gg); or

(h) Is not required by the Part 70 program to be processed as a significant modification.

However, because the source is transitioning its operating permit from a Federally Enforceable State Operating Permit (FESOP) to a Part 70 Operating Permit, the issuance of the Part 70 Operating Permit itself will grant the source the appropriate operating approval for the proposed modification. Therefore, there will be no need to issue a distinct minor permit modification for this proposed modification.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 source modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

	Potential to Emit (tons/yr)							
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**VOC**	**CO**	**NO_X**	**GHGs**
Fork Truck Unloading Area (EU075) - Pneumatic	2.79	2.79	2.79	-	-	-	-	-
Total for Modification	**2.79**	**2.79**	**2.79**	**0**	**0**	**0**	**0**	**0**
PSD Major Source Thresholds	250	250	250	250	250	250	250	N/A
Significant Level	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75,000 CO_2e

*$PM_{2.5}$ listed is direct $PM_{2.5}$.

This modification to an existing minor stationary source is not major because the emissions increase is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

On July 20, 2011, U.S. EPA issued a deferral of biogenic CO_2 emissions from PSD and Title V. Therefore, these CO_2 emissions were not included in the listed GHG emissions.

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.

	Potential to Emit (tons/yr)							
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**VOC**	**CO**	**NO_X**	**GHGs**
Existing Source	123.51	75.99	64.08	<100	<100	<100	<100	>100,000
Boiler #1 and Boiler #2	0.79	3.14	3.14	0.25	41.36	2.27	34.74	49,935
Non-Fuel Grade Ethanol Loadout and Flare	negl.	negl.	negl.	negl.	2.31	0.22	3.87	5,184
Fork Truck Unloading Area (EU075) - Pneumatic	2.79	2.79	2.79	-	-	-	-	-
PTE After Issuance	**126.31**	**78.79**	**66.86**	**<250**	**<250**	**<250**	**<250**	**>100,000**
PSD Major Source Thresholds	250	250	250	250	250	250	250	N/A

1) PM is filterable PM only. PM10 is based on the filterable and condensable PM emission factors. PM2.5 is a subset of PM10. If one assumes all PM10 to be all direct PM2.5, then a worst case assumption of direct PM2.5 can be made.

PSD Minor Limits

In order to render the requirements of 326 IAC 2-2 (PSD) not applicable, the source shall comply with the follow:

(1) PM emissions from the Fork Truck Unloading Area shall not exceed 0.64 lb/hr.

(2) PM_{10} emissions from the Fork Truck Unloading Area shall not exceed 0.64 lb/hr.

(3) $PM_{2.5}$ emissions from the Fork Truck Unloading Area shall not exceed 0.64 lb/hr.

(4) The total combined non-fuel grade ethanol load-out from loading skids EU083 and EU084 shall not exceed 60,000,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

(5) CO emissions from flare CE019, controlling ethanol loading skids EU083 and EU084, shall not exceed 0.129 lb/kgal.

(6) NO_x emissions from flare CE019, controlling ethanol loading skids EU083 and EU084, shall not exceed 0.077 lb/kgal.

Compliance with the following PM, PM_{10}, $PM_{2.5}$, VOC, CO, and NOx limits, combined with the potential to emit PM, PM_{10}, $PM_{2.5}$, VOC, CO, and NOx from other emission units at the source, shall limit the PM, PM_{10}, $PM_{2.5}$, VOC, CO, and NOx emissions from the entire source to less than 250 tons per twelve (12) consecutive month period and render 326 IAC 2-2 (PSD) not applicable.

Federal Rule Applicability

CAM:

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each existing emission unit and specified pollutant subject to CAM:

Emission Unit / Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Fork Truck Unloading Area (EU075): PM	Baghouse CE016	Y*	---	---	100	N	---
Ethanol Loadout (EU083 and EU084): VOC	Enclosed Flare CE019	Y	< 100	---	100	N	---

* Although a control device is present, it is not necessary in order for the emission unit to comply with the applicable emission limitations. Therefore, CAM is not applicable to this emission unit for this pollutant.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the modified units as part of this modification.

NSPS:

(a) The two (2) natural gas fired boilers are subject to the requirements of the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60.40c, Subpart Dc, which is incorporated by reference as 326 IAC 12, because each boiler will beconstructed after June 19, 1984 and has a maximum heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr.

The facilities subject to this rule include the following:

(1) Two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat input rate of 48.16 MMBtu/hr, exhausting uncontrolled to stacks EP020 and EP021, respectively.

Under 40 CFR 60, Subpart Dc, EU081 and EU082 are affected facilities.

The entire rule has been included as Attachment G to the permit. This facility is subject to the following portions of 40 CFR 60, Subpart Dc:

(1) 40 CFR 60.40c(a), (b), (c), (d);
(2) 40 CFR 60.41c; and
(3) 40 CFR 60.48c(a), (f)(4), (g), (i), (j).

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12, applies to EU081 and EU082 except as otherwise specified in 40 CFR 60, Subpart Dc.

(b) Tanks T001 through T005 and Tanks T013 through T017 are subject to the New Source Performance Standards for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (40 CFR 60, Subpart Kb) because they each have capacities greater than 75 cubic meters (19,813 gallons) and will be used to store volatile organic liquids.

The facilities subject to this rule include the following:

(1) Two (2) liquid storage tanks, identified as T013 and T014, each with a maximum capacity of 500,000 gallons.

Under 40 CFR 60, Subpart Kb, T013 and T014 are affected facilities.

(2) Three (3) liquid storage tanks, identified as T015, T016, and T017, each with a maximum capacity of 24,000 gallons.

Under 40 CFR 60, Subpart Kb, T015, T016, and T017 are affected facilities.

The entire rule has been included as Attachment D to the permit. These facilities are subject to the following portions of 40 CFR 60, Subpart Kb:

(1) 40 CFR 60.110b(a), (b), (d)(2), (d)(3), (d)(7), (d)(8), (e)(1)(i), (e)(2), (e)(3);
(2) 40 CFR 60.111b;
(3) 40 CFR 60.112b(a)(1);
(4) 40 CFR 60.113b(a);
(5) 40 CFR 60.115b(a);
(6) 40 CFR 60.116b(a), (b), (c), (e); and
(7) 40 CFR 60.117b.

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12, applies to the affect facilities except as otherwise specified in 40 CFR 60, Subpart Kb.

(c) Ethanol is one of the chemicals listed in 40 CFR 60.489. Therefore, this ethanol production plant is subject to the requirements of 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 (40 CFR 60.480a, Subpart VVa). By complying with the provisions of NSPS VVa, the source is satisfying the requirements of NSPS VV for those affected units for which construction, reconstruction, or modification commenced after January 5, 1981, and on or before November 7, 2006.

The facilities subject to this rule include the following:

(1) One (1) distillation process, approved in 2013 for construction, with a maximum throughput rate of 40,000 gallons of non-fuel grade ethanol per hour, consisting of the following:

(1) Three (3) distillation columns and seven (7) condensers operating in a close loop.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(2) One (1) non-fuel grade ethanol loading skid for trucks, identified as EU083, approved in 2013 for construction, with a maximum throughput rate of 1000 gallons per minute. The truck loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

(3) One (1) non-fuel grade ethanol loading skid for railcars, identified as EU084, approved in 2013 for construction, with a maximum throughput rate of 1667 gallons per minute. The railcar loading process is controlled by the enclosed flare CE019, which is fueled by natural gas and has a maximum heat input capacity of 10.0 MMBtu/hr, and exhausts through stack EP019.

Under NSPS, Subpart VVa, the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of this process are considered to be affected facilities.

The entire rule has been included as Attachment C to the permit. These facilities are subject to the following portions of 40 CFR 60, Subpart VVa:

(1) 40 CFR 60.480a(a), (b), (c), (d);
(2) 40 CFR 60.481a;
(3) 40 CFR 60.482-1a;
(4) 40 CFR 60.482-2a;
(5) 40 CFR 60.482-3a;
(6) 40 CFR 60.482-4a;

(7) 40 CFR 60.482-5a;
(8) 40 CFR 60.482-6a;
(9) 40 CFR 60.482-7a;
(10) 40 CFR 60.482-8a;
(11) 40 CFR 60.482-9a;
(12) 40 CFR 60.482-10a;
(13) 40 CFR 60.482-11a;
(14) 40 CFR 60.483-1a;
(15) 40 CFR 60.483-2a;
(16) 40 CFR 60.484a;
(17) 40 CFR 60.485a;
(18) 40 CFR 60.486a;
(19) 40 CFR 60.487a;
(20) 40 CFR 60.488a; and
(21) 40 CFR 60.489a.

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12, applies to the affected facilities except as otherwise specified in 40 CFR 60, Subpart VVa.

NESHAP:

(d) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20, and 40 CFR Part 63) applicable to this proposed modification.

State Rule Applicability Determination

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

326 IAC 2-2 (PSD)

This modification to an existing minor stationary source is not major because the emissions increase is less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))

With the addition of the proposed modification, Central Indiana Ethanol, LLC would have potential to emit total HAPs greater than 25 tons per year, making Central Indiana Ethanol, LLC a major source of HAPs. Central Indiana Ethanol, LLC has elected to comply with the following limits in order for the source to meet the definition of an "area source":

(a) The potential emissions of cumulative HAPs shall be limited to no more than 3.85 tons per year from Tanks T013 through T017 and shall be limited to any single HAP or combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl isobutyl ketone, and toluene.

(b) The total combined non-fuel grade ethanol load-out from loading skids EU083 and EU084 shall not exceed 60,000,000 gallons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with these HAP limits, combined with the potential to emit HAP from other emission units at the source, shall limit the HAP emissions from the entire source to less than 10 tons per twelve (12) consecutive month period for a single HAP and less than 25 tons per twelve (12) consecutive month period for total HAPs. Therefore, the requirements of 326 IAC 2-4.1 are not included in the permit.

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)
The two (2) natural gas fired boilers, identified as Boiler #1 (EU081) and Boiler #2 (EU082), each with a maximum heat capacity of 48.16 MMBtu/hr, are subject to 326 IAC 6-2-4 because they will be constructed after September 21, 1983.

Pursuant to 326 IAC 6-2-4(a), the particulate matter (PM) emissions from each boiler shall not exceed the pound per million Btu limit calculated using the following equation:

$$Pt = 1.09/Q^{0.26}$$

Where:
Pt = Pounds of particulate matter emitted per MMBtu heat input
Q = Total source maximum operating capacity rating in MMBtu/hr heat input
(Q = 135 + 48.16 + 48.16 = 231.32 MMBtu/hr)

Pt = 0.26 lb/MMBtu.

The AP-42 emission factor for filterable PM from natural gas combustion is 1.9 lb/MMCF, which is equivalent to 0.00186 lb/MMBtu assuming natural gas has a heating value of 1,020 MBtu/MMCF. Therefore, each of the boilers is capable of complying with this rule.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

(a) Pursuant to 326 IAC 6-3-2, particulate emissions from each of following operations shall not exceed the pound per hour limit listed in the table below:

Unit ID	Unit Description	Max. Throughput Rate (tons/hr)	Particulate Emission Limit (lb/hr)
EU075	Fork Truck Unloading Area	25	35.43

The pounds per hour limitations were calculated using the following equation:

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

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

(b) The non-fuel grade ethanol loading skids (EU083 and EU084) will have potential particulate emissions less than 0.551 pounds per hour. Therefore, pursuant to 326 IAC 6-3-1(b)(14), these units are not subject to the requirements of 326 IAC 6-3-2.

326 IAC 8-1-6 (New Facilities; General Reduction Requirements (BACT))
326 IAC 8-1-6 does not apply to the remaining units at this source since the potential VOC emissions from each emission unit are less than twenty-five (25) tons per year.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)

(a) Tanks T013 and T014 will not be used to store petroleum distillate; they will store ethanol distillates that are not based from petroleum. Therefore, these tanks are not subject to requirements of 326 IAC 8-4-3.

(b) Tanks T015, T016, and T017 have individual storage capacities less than the applicability threshold of 39,000 gallons set forth in 326 IAC 8-4-3. Therefore, these tanks are not subject to requirements of 326 IAC 8-4-3.

326 IAC 8-5-6 (Fuel Grade Ethanol Production at Dry Mills)
Since the proposed distillation process will only produce non-fuel grade ethanol, the requirements of 326 IAC 8-5-6 do not apply to the process.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source’s failure to take the appropriate corrective actions within a specific time period.

The compliance determination requirements applicable to the non-fuel grade ethanol loading skids are as follows:

(1) Testing Requirements
No later than five (5) years after the date of the most recent valid compliance demonstration, compliance with the VOC, CO, and NO_x emission limitations for enclosed flare CE019 shall be determined by a performance stack test. Testing shall be repeated every five (5) years. The VOC testing shall include emission rate, capture efficiency, and destruction efficiency.

(2) Emission Controls Operation

(A) Enclosed flare CE019 for VOC and HAP control shall be in operation and control emissions from the non-fuel grade ethanol loading skids (EU083 and EU084) at all times when these racks are in operation.

(B) The non-fuel grade ethanol loading skids (EU083 and EU084) shall utilize submerged loading method.

(C) The railcars and trucks shall not use vapor balance services.

These requirements are required to ensure compliance with 326 IAC 8-5-6 (Fuel Grade Ethanol Production at Dry Mills) and to render 326 IAC 2-2 (PSD) and 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants) not applicable.

The compliance monitoring requirements applicable to the non-fuel grade ethanol loading skids are as follows:

The Permittee shall monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame when the non-fuel grade ethanol loading racks EU083 and/or EU084 are in operation.

These monitoring conditions are necessary because the flare must operate properly to ensure compliance with 326 IAC 2-2 (PSD) and 326 IAC 2-7 (Part 70).

Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 053-32519-00062. The staff recommends to the Commissioner that this Part 70 Minor Source Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Julie Alexander 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) 3-1782 or toll free at 1-800-451-6027 extension 3-1782.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

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

Appendix A: Emission Calculations
Emissions Summary
Uncontrolled Potential to Emit

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Potential to Emit Before Control (tons/yr)									
		PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO	NO_x	GHGs as CO_2e	Total HAPs	Worst HAP
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	732.09	732.09	124.45	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	525.60	525.60	89.35	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	70.39	70.39	11.97	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	227.50	227.50	38.68	-	9.68	-	-	-	0.53	0.33
Corn Storage Bin (EU066)	N/A	64.39	14.35	2.44	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 &	CE015	3.54	3.54	3.54	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	1.44	1.44	1.44	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	0.84	0.84	0.84	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	-	-	-	-	1,434.45	-	-	-	0.47	0.26
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	-	-	-	-	98.55	-	-	-	0.21	0.00
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007) *	CE006 / CE007	0.73	2.94	2.94	0.23	2.13	32.46	31.57	116,647	0.75	-
		1.10	4.41	4.41	0.35	3.19	48.70	46.38		1.13	-
		171.58	171.58	171.58	210.24	1,256.37	612.76	0.00	-	35.48	6.13
Ethanol Loadout & Flare (EU045A and EU045B) (EP009) **	CE009	negl.	negl.	negl.	negl.	1,208.80	27.12	16.19	5,184	70.40	-
Fire Pump (EU034) (EP006)	N/A	0.07	0.17	0.17	0.04	0.19	0.43	1.29	86	0.00	0.00
Biomethanator Flare (EU048) (EP013)	CE013	negl.	negl.	negl.	negl.	1.37	9.72	1.79	3,111	0.05	-
Space Heaters	N/A	0.02	0.08	0.08	0.01	0.06	0.90	1.07	1,296	0.02	-
EPCO Plant - Space Heaters	N/A	0.01	0.02	0.02	negl.	0.01	0.23	0.27	327	0.01	-
Total Existing Emission Units	-	**1,799.30**	**1,754.95**	**451.91**	**210.86**	**4,014.79**	**732.32**	**98.56**	**126,651**	**109.05**	**6.73**
Proposed Modification - NonFuel Grade Ethanol											
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	0.79	3.14	3.14	0.25	2.27	34.74	41.36	49,935	0.78	-
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019) ***	CE019	negl.	negl.	negl.	negl.	63.53	22.60	13.49	5,184	0.08	-
Total Proposed NonFuel Grade Ethanol	-	**0.79**	**3.14**	**3.14**	**0.25**	**65.81**	**57.34**	**54.85**	**55,119**	**0.86**	-
Source Total after NonFuel Grade Ethanol Modification	-	**1800.09**	**1758.09**	**455.05**	**211.11**	**4080.60**	**789.67**	**153.41**	**181,770**	**109.91**	**6.73**
Proposed Modification - Pneumatic Conveyance System											
Fork Truck Unloading Area (EU075)	CE022	24.92	24.92	24.92	-	-	-	-	-	-	-
	CE016	2.77	2.77	2.77	-	-	-	-	-	-	-
Total Proposed Pneumatic Conveyance System	-	**27.69**	**27.69**	**27.69**	-	-	-	-	-	-	-
SOURCE TOTAL (PSD Applicability)	-	**1,827.78**	**1,785.78**	**482.74**	**211.11**	**4,080.60**	**789.67**	**153.41**	**181,770**	**109.91**	**6.73**
Fugitive Emissions											
Uncaptured Emissions From Grain Receiving (F001)	N/A	2.26	0.50	0.50	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	8.36	1.71	0.40	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	1.01	0.20	0.05	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	-	-	-	-	13.20	-	-	-	2.62	0.01
Cooling Tower (F004)	N/A	9.05	9.05	9.05	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	0.25	0.25	0.25	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	-	-	-	-	0.54	-	-	-	0.29	negl.
Storage Tanks (T001 - T010)	N/A	-	-	-	-	4.33	-	-	-	-	-
Total Existing Fugitives	-	**20.93**	**11.71**	**10.25**	**0.00**	**18.07**	**0.00**	**0.00**	**0**	**2.91**	**0.01**
Proposed Modification - NonFuel Grade Ethanol											
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	-	-	-	-	11.35	-	-	-	0.67	-
Cooling Tower - NonFuel Grade Ethanol Distillation Process (F004)	N/A	5.76	5.76	5.76	-	-	-	-	-	-	1.95
Storage Tanks (T013 - T017)	N/A	-	-	-	-	3.85	-	-	-	3.85	-
Total Proposed Fugitives	-	**5.76**	**5.76**	**5.76**	**0.00**	**15.19**	**0.00**	**0.00**	**0**	**4.52**	**1.95**
SOURCE TOTAL (FUGITIVES)	-	**26.69**	**17.47**	**16.00**	**0.00**	**33.26**	**0.00**	**0.00**	**0**	**7.43**	**1.96**
SOURCE TOTAL (Part 70 Applicability)	-	**1,827.78**	**1,785.78**	**482.74**	**211.11**	**4,080.60**	**789.67**	**153.41**	**181,770**	**109.91**	**6.73**

Notes:
Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.
HAP fugitive emissions are counted only toward the determination of Part 70 applicability.
* These totals include the combustion emissions and the process emissions from both the DDGS dryers and the TO/HSRG.
** These totals include the combustion emissions and the process emissions from the ethanol loadout and flare.
*** These totals include the combustion emissions and the process emissions from the non-fuel grade ethanol loadout and flare.

Appendix A: Emission Calculations
Emissions Summary
Controlled Potential to Emit

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Potential to Emit Before Control (tons/yr)									
		PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO	NO_x	GHGs as CO_2e	Total HAPs	Worst HAP
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	7.32	7.32	1.24	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	5.26	5.26	0.89	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	0.70	0.70	0.12	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	2.28	2.28	0.39	-	9.68	-	-	-	0.53	0.33
Corn Storage Bin (EU066)	N/A	64.39	14.35	2.44	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 &	CE015	3.54E-03	3.54E-03	6.02E-04	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	1.44E-03	1.44E-03	2.45E-04	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	8.42E-04	8.42E-04	1.43E-04	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	-	-	-	-	5.74	-	-	-	0.24	0.13
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	-	-	-	-	0.04	-	-	-	0.11	1.75E-03
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007)	CE006 / CE007	0.73	2.94	2.94	1.27	4.77	61.28	42.22	116,647	0.75	-
		1.10	4.41	4.41						1.13	-
		17.16	17.16	17.16					-	3.55	0.61
Ethanol Loadout & Flare (EU045A and EU045B) (EP009)	CE009	negl.	negl.	negl.	negl.	24.18	27.12	16.19	5,184	1.41	-
Fire Pump (EU034) (EP006)	N/A	0.07	0.17	0.17	0.04	0.19	0.43	1.29	86	0.00	0.00
Biomethanator Flare (EU048) (EP013)	CE013	negl.	negl.	negl.	negl.	1.37	9.72	1.79	3,111	0.05	-
Space Heaters	N/A	0.02	0.08	0.08	0.01	0.06	0.90	1.07	1,296	0.02	-
Total Existing Emission Units	-	**99.03**	**54.66**	**29.83**	**1.32**	**46.02**	**99.45**	**62.56**	**126,324**	**7.77**	**1.08**
Proposed Modification - NonFuel Grade Ethanol											
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	0.79	3.14	3.14	0.25	2.27	34.74	41.36	49,935	0.78	-
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019)	CE019	negl.	negl.	negl.	negl.	1.27	22.60	13.49	5,184	0.15	-
Total Proposed Emission Units	-	**0.79**	**3.14**	**3.14**	**0.25**	**3.55**	**57.34**	**54.85**	**55,119**	**0.94**	-
Source Total after NonFuel Grade Ethanol Modification	-	**99.81**	**57.80**	**32.98**	**1.56**	**49.57**	**156.80**	**117.41**	**181443.47**	**8.71**	**1.08**
Proposed Modification - Pneumatic Conveyance System											
Fork Truck Unloading Area (EU075)	CE022	2.49E-02	2.49E-02	4.24E-03	-	-	-	-	-	-	-
	CE016	2.77E-03	2.77E-03	4.71E-04	-	-	-	-	-	-	-
Total Proposed Pneumatic Conveyance System	-	**2.77E-02**	**2.77E-02**	**4.71E-03**	-	-	-	-	-	-	-
SOURCE TOTAL (PSD Applicability)	-	**99.84**	**57.83**	**32.98**	**1.56**	**49.57**	**156.80**	**117.41**	**181,443**	**8.71**	**1.08**
Fugitive Emissions											
Uncaptured Emissions From Grain Receiving (F001)	N/A	2.26	0.50	0.50	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	4.18	0.86	0.20	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	0.50	0.10	0.02	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	-	-	-	-	13.20	-	-	-	0.78	negl.
Cooling Tower (F004)	N/A	9.05	9.05	9.05	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	0.25	0.25	0.25	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	-	-	-	-	0.54	-	-	-	0.29	negl.
Storage Tanks (T001 - T010)	N/A	-	-	-	-	4.33	-	-	-	-	-
Total Existing Fugitives	-	**16.24**	**10.76**	**10.02**	**0.00**	**18.07**	**0.00**	**0.00**	**0**	**1.07**	**negl.**
Proposed Modification - NonFuel Grade Ethanol											
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	-	-	-	-	3.39	-	-	-	0.20	2.64E-03
Cooling Tower - NonFuel Grade Ethanol Distillation Process (F004)	N/A	5.76	5.76	5.76	-	-	-	-	-	-	-
Storage Tanks (T013 - T017)	N/A	-	-	-	-	3.85	-	-	-	3.85	-
Total Proposed Fugitives	-	**5.76**	**5.76**	**5.76**	-	**7.24**	-	-	-	**4.05**	**2.64E-03**
SOURCE TOTAL (FUGITIVES)	-	**22.00**	**16.51**	**15.78**	**0.00**	**25.31**	**0.00**	**0.00**	**0**	**5.12**	**2.64E-03**
SOURCE TOTAL (Part 70 Applicability)	-	**99.84**	**57.83**	**32.98**	**1.56**	**49.57**	**156.80**	**117.41**	**181,443**	**8.71**	**1.08**

Notes:
Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.
HAP fugitive emissions are counted only toward the determination of Part 70 applicability.

Appendix A: Emission Calculations
Emissions Summary
Potential to Emit After Issuance of Permit (Limited PTE)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Potential to Emit Before Control (tons/yr)									
		PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO	NO_x	GHGs as CO_2e	Total HAPs	Worst HAP
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	7.31	7.31	7.31	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	5.26	5.26	5.26	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	0.70	0.70	0.70	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	4.12	4.12	4.12	-	6.83	-	-	-	0.53	0.33
Corn Storage Bin (EU066)	N/A	64.39	14.35	2.44	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 & EU077)	CE015	3.54	3.54	3.54	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	1.44	1.44	1.44	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	0.84	0.84	0.84	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	-	-	-	-	41.61	-	-	-	8.37	8.23
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	-	-	-	-	2.72	-	-	-	0.57	0.50
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007)	CE006 / CE007	35.04	35.04	35.04	37.23	22.56	91.98	86.29	116,647 -	2.32	0.79
Ethanol Loadout & Flare (EU045A and EU045B) (EP009)	CE009	negl.	negl.	negl.	negl.	3.23	4.19	2.50	5,184	0.19	-
Fire Pump (EU034) (EP006)	N/A	0.07	0.17	0.17	0.04	0.19	0.43	1.29	86	0.00	4.03E-04
Biomethanator Flare (EU048) (EP013)	CE013	*see note									
Space Heaters	N/A	0.02	0.08	0.08	0.01	0.06	0.90	1.07	1,296	0.02	-
Total Existing Emission Units	-	**122.73**	**72.85**	**60.94**	**37.27**	**77.19**	**97.50**	**91.15**	**123,213**	**11.99**	**9.85**
Proposed Modification - NonFuel Grade Ethanol											
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	0.79	3.14	3.14	0.25	2.27	34.74	41.36	49,935	0.78	-
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019)	CE019	negl.	negl.	negl.	negl.	0.22	3.87	2.31	5,184	0.09	-
Total Proposed Emission Units	-	**0.79**	**3.14**	**3.14**	**0.25**	**2.49**	**38.61**	**43.67**	**55,119**	**0.87**	-
Source Total after NonFuel Grade Ethanol Modification	-	**123.51**	**75.99**	**64.08**	**37.52**	**79.68**	**136.11**	**134.82**	**178,333**	**12.87**	**9.85**
Proposed Modification - Pneumatic Conveyance System											
Fork Truck Unloading Area (EU075)	CE022	2.49E-02	2.49E-02	4.24E-03	-	-	-	-	-	-	-
	CE016	2.77	2.77	2.77	-	-	-	-	-	-	-
Total Proposed Pneumatic Conveyance System	-	**2.79**	**2.79**	**2.77**	-	-	-	-	-	-	-
SOURCE TOTAL (PSD Applicability)	-	**126.31**	**78.79**	**66.86**	**37.52**	**79.68**	**136.11**	**134.82**	**178,333**	**12.87**	**9.85**
Fugitive Emissions											
Uncaptured Emissions From Grain Receiving (F001)	N/A	2.26	0.50	0.50	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	4.18	0.86	0.20	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	0.50	0.10	0.02	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	-	-	-	-	13.20	-	-	-	0.78	negl.
Cooling Tower (F004)	N/A	9.05	9.05	9.05	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	0.25	0.25	0.25	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	-	-	-	-	0.54	-	-	-	0.29	negl.
Storage Tanks (T001 - T010)	N/A	-	-	-	-	4.33	-	-	-	-	-
Total Existing Fugitives	-	**16.24**	**10.76**	**10.02**	-	**18.07**	-	-	-	**1.07**	-
Proposed Modification - NonFuel Grade Ethanol											
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	-	-	-	-	3.39	-	-	-	0.20	-
Cooling Towers - NonFuel Grade Ethanol Distillation Process (F004)	N/A	5.76	5.76	5.76	-	-	-	-	-	-	-
Storage Tanks (T013 - T017)	N/A	-	-	-	-	3.85	-	-	-	3.85	-
Total Proposed Fugitives	-	**5.76**	**5.76**	**5.76**	-	**7.24**	-	-	-	**4.05**	-
SOURCE TOTAL (FUGITIVES)	-	**22.00**	**16.51**	**15.78**	**0.00**	**25.31**	**0.00**	**0.00**	**0**	**5.12**	**negl.**
SOURCE TOTAL (Part 70 Applicability)	-	**126.31**	**78.79**	**66.86**	**37.52**	**79.68**	**136.11**	**134.82**	**178,333**	**12.87**	**9.85**

Notes:
Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.
HAP fugitive emissions are counted only toward the determination of Part 70 applicability.
* The biomethanator flare only operates when the DDGS dryers are down. The operation of the DDGS dryers is the worst case scenario for emissions, and the emissions from the DDGS dryers have been included in the total PTE.

Appendix A: Emission Calculations
HAP Emissions Summary
Uncontrolled Potential to Emit

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Potential to Emit Before Control (tons/yr)										
		Acetaldehyde	Acrolein	Benzene	Chloroform	Dimethyl Phthalate	Formaldehyde	Hexane	Methanol	Methyl Isobutyl Ketone	Toluene	Total HAPs
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	-	-	-	-	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	-	-	-	-	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	-	-	-	-	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	0.33	0.07	-	-	-	0.07	-	0.07	-	-	0.53
Corn Storage Bin (EU066)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 &	CE015	-	-	-	-	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	-	-	-	-	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	-	-	-	-	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	0.26	0.09	-	-	-	0.04	-	0.09	-	-	0.47
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	1.75E-03	0.09	-	-	-	0.04	-	0.09	-	-	0.21
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007) *	CE006 / CE007	-	-	negl.	-	-	0.03	0.71	-	-	negl.	0.75
		-	-	negl.	-	-	0.04	1.06	-	-	negl.	1.13
		6.13	3.94	-	-	-	4.38	-	3.07	-	-	35.48
Ethanol Loadout & Flare (EU045A and EU045B) (EP009) **	CE009	-	-	3.02	-	-	negl.	60.52	-	-	6.04	70.40
Fire Pump (EU034) (EP006)	N/A	4.03E-04	4.86E-05	4.90E-04	-	-	6.20E-04	-	-	-	2.15E-04	2.08E-03
Biomethanator Flare (EU048) (EP013)	CE013	-	-	negl.	-	-	negl.	0.05	-	-	negl.	0.05
Space Heaters	N/A	-	-	negl.	-	-	negl.	0.02	-	-	negl.	0.02
EPCO Plant - Space Heaters	N/A	-	-	negl.	-	-	negl.	negl.	-	-	negl.	0.01
Total Existing Emission Units	-	**6.73**	**4.18**	**3.02**	**0.00**	**0.00**	**4.59**	**62.36**	**3.31**	**0.00**	**6.04**	**109.05**
Proposed Modification - NonFuel Grade Ethanol												
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	-	-	negl.	-	-	0.03	0.74	-	-	negl.	0.78
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019) ***	CE019	-	-	0.16	-	-	negl.	3.25	-	-	0.32	0.08
Total Proposed Emission Units	-	**0.00**	**0.00**	**0.16**	**0.00**	**0.00**	**0.03**	**4.00**	**0.00**	**0.00**	**0.32**	**0.86**
Proposed Modification - Pneumatic Conveyance System												
Fork Truck Unloading Area (EU075)	CE016	-	-	-	-	-	-	-	-	-	-	-
	CE022	-	-	-	-	-	-	-	-	-	-	-
Total Proposed Emission Units	-	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
SOURCE TOTAL (PSD Applicability)	-	**6.73**	**4.18**	**3.18**	**0.00**	**0.00**	**4.62**	**66.36**	**3.31**	**0.00**	**6.36**	**109.91**
Fugitive Emissions												
Uncaptured Emissions From Grain Receiving (F001)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	0.01	-	0.11	-	-	-	2.21	0.01	-	0.22	2.62
Cooling Tower (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	negl.	negl.	-	-	-	negl.	-	0.06	-	-	0.29
Storage Tanks (T001 - T010)	N/A	-	-	-	-	-	-	-	-	-	-	-
Total Existing Fugitives	-	**0.01**	**0.00**	**0.11**	**0.00**	**0.00**	**0.00**	**2.21**	**0.07**	**0.00**	**0.22**	**2.91**
Proposed Modification												
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	2.64E-03	-	0.03	-	-	-	0.57	negl.	-	0.06	0.67
Cooling Tower - NonFuel Grade Ethanol Distillation Process (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Storage Tanks (T013 - T017) (a)	N/A	-	-	1.95	1.95	1.95	-	-	-	1.95	1.95	3.85
Total Proposed Fugitives	-	**2.64E-03**	**0.00**	**1.98**	**1.95**	**1.95**	**0.00**	**0.57**	**negl.**	**1.95**	**2.01**	**4.52**
SOURCE TOTAL (FUGITIVES)	-	**0.01**	**0.00**	**2.09**	**1.95**	**1.95**	**0.00**	**2.77**	**7.01E-02**	**1.95**	**2.23**	**7.43**
SOURCE TOTAL (Part 70 Applicability)	-	**6.74**	**4.18**	**5.27**	**1.95**	**1.95**	**4.62**	**69.13**	**3.38**	**1.95**	**8.59**	**117.34**

Notes:
Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.
HAP fugitive emissions are counted only toward the determination of Part 70 applicability.
(a) The potential HAPs from the tanks will be limited to any one of these HAPs or a combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl idobutyl ketone, and toluene.
* These totals include the combustion emissions and the process emissions from both the DDGS dryers and the TO/HSRG.
** These totals include the combustion emissions and the process emissions from the ethanol loadout and flare.
*** These totals include the combustion emissions and the process emissions from the non-fuel grade ethanol loadout and flare.

Appendix A: Emission Calculations
HAP Emissions Summary
Controlled Potential to Emit

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Potential to Emit After Control (tons/yr)										
		Acetaldehyde	Acrolein	Benzene	Chloroform	Dimethyl Phthalate	Formaldehyde	Hexane	Methanol	Methyl Isobutyl Ketone	Toluene	Total HAPs
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	-	-	-	-	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	-	-	-	-	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	-	-	-	-	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	0.33	0.07	-	-	-	0.07	-	0.07	-	-	0.53
Corn Storage Bin (EU066)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 &	CE015	-	-	-	-	-	-	-	-	-	-	-
Fork Truck Unloading Area (EU075)	CE016	-	-	-	-	-	-	-	-	-	-	-
	CE022	-	-	-	-	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	-	-	-	-	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	-	-	-	-	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	0.13	0.04	0.00	0.00	0.00	0.02	0.04	0.00	-	-	0.24
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	0.00	0.04	0.00	0.00	0.00	0.02	0.04	0.00	-	-	0.11
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007)	CE006 / CE007	-	-	negl.	-	-	0.03	0.71	-	-	negl.	0.75
		-	-	negl.	-	-	0.04	1.06	-	-	negl.	1.13
		0.61	0.39	0.90	0.90	3.94	0.44	0.31	0.00	-	-	3.55
Ethanol Loadout & Flare (EU045A and EU045B) (EP009)	CE009	-	-	0.06	-	-	negl.	1.29	-	-	0.12	1.41
Fire Pump (EU034) (EP006)	N/A	4.03E-04	4.86E-05	4.90E-04	-	-	6.20E-04	-	-	-	2.15E-04	2.08E-03
Biomethanator Flare (EU048) (EP013)	CE013	-	-	negl.	-	-	negl.	0.05	-	-	negl.	0.05
Space Heaters	N/A	-	-	negl.	-	-	negl.	0.02	-	-	negl.	0.02
Total Existing Emission Units	-	**1.08**	**0.55**	**0.96**	**0.90**	**3.94**	**0.61**	**3.52**	**0.07**	**0.00**	**0.12**	**7.77**
Proposed Modification												
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	-	-	negl.	-	-	0.03	0.74	-	-	negl.	0.78
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019)	CE019	-	-	negl.	-	-	negl.	0.14	-	-	0.01	0.15
Total Proposed Emission Units	-	**0.00**	**0.00**	**negl.**	**0.00**	**0.00**	**0.03**	**0.89**	**0.00**	**0.00**	**0.01**	**0.94**
Proposed Modification - Pneumatic Conveyance System												
Fork Truck Unloading Area (EU075)	CE016	-	-	-	-	-	-	-	-	-	-	-
	CE022	-	-	-	-	-	-	-	-	-	-	-
Total Proposed Emission Units	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOURCE TOTAL (PSD Applicability)	-	1.08	0.55	0.96	0.90	3.94	0.64	4.41	0.07	0.00	0.13	8.71
Fugitive Emissions												
Uncaptured Emissions From Grain Receiving (F001)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	negl.	-	0.03	-	-	-	0.66	negl.	-	0.07	0.78
Cooling Tower (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	negl.	negl.	-	-	-	negl.	-	0.06	-	-	0.29
Storage Tanks (T001 - T010)	N/A	-	-	-	-	-	-	-	-	-	-	-
Total Existing Fugitives	-	negl.	negl.	0.03	0.00	0.00	negl.	0.66	0.06	0.00	0.07	1.07
Proposed Modification												
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	2.64E-03	-	0.01	-	-	-	0.17	negl.	-	0.02	0.20
Cooling Tower - NonFuel Grade Ethanol Distillation Process (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Storage Tanks (T013 - T017) (a)	N/A	-	-	1.95	1.95	1.95	-	-	-	1.95	1.95	3.85
Total Proposed Fugitives	-	**2.64E-03**	**0.00**	**1.96**	**1.95**	**1.95**	**0.00**	**0.17**	**0.00**	**1.95**	**1.97**	**4.05**
SOURCE TOTAL (FUGITIVES)	-	2.64E-03	0.00	1.99	1.95	1.95	0.00	0.83	0.06	1.95	2.03	5.12
SOURCE TOTAL (Part 70 Applicability)	-	1.08	0.55	2.95	2.85	5.89	0.64	5.24	0.13	1.95	2.16	13.83

Notes:

(a) The potential HAPs from the tanks will be limited to any one of these HAPs or a combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl idobutyl ketone, and toluene.

Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.

HAP fugitive emissions are counted only toward the determination of Part 70 applicability.

Appendix A: Emission Calculations
HAP Emissions Summary
Potential to Emit After Issuance of Permit (Limited PTE)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Process, Emission Units, Stack	Control Device	Limited Potential to Emit (tons/yr)										
		Acetaldehyde	Acrolein	Benzene	Chloroform	Dimethyl Phthalate	Formaldehyde	Hexane	Methanol	Methyl Isobutyl Ketone	Toluene	Total HAPs
Grain Receiving and Handling (EU001 - EU007, EU064) (EP001)	CE001	-	-	-	-	-	-	-	-	-	-	-
Hammermills (EU010, EU011, and EU067) (EP003)	CE003	-	-	-	-	-	-	-	-	-	-	-
DDGS Handling and Loadout (EU040 - EU043) (EP008)	CE008	-	-	-	-	-	-	-	-	-	-	-
DDGS Cooler (EU036) (EP014)	CE014	0.33	0.07	-	-	-	0.07	-	0.07	-	-	0.53
Corn Storage Bin (EU066)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 &	CE015	-	-	-	-	-	-	-	-	-	-	-
Fork Truck Unloading Area (EU075)	CE016	-	-	-	-	-	-	-	-	-	-	-
	CE022	-	-	-	-	-	-	-	-	-	-	-
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	-	-	-	-	-	-	-	-	-	-	-
Truck Unloading Area (EU080)	CE018	-	-	-	-	-	-	-	-	-	-	-
Fermentation Scrubber (EU016 through EU020) (EP005)	CE005	8.23	0.09	-	-	-	0.04	-	0.09	-	-	8.37
Fermentation Scrubber (EU016 through EU020) (EP010)	CE010	0.50	0.09	-	-	-	0.04	-	0.09	-	-	0.57
DDGS Dryers (EU035 and EU056) & TO/HSRG (EU014, EU015, EU021 through EU029, EU049 through EU055, EU058, EU059, EU068 and EU069) (EP007)*	CE006 / CE007	0.79	2.32	negl.	-	-	2.32	0.71	2.32	-	negl.	2.32
				negl.	-	-		1.06		-	negl.	
				-	-	-		-		-	-	
Ethanol Loadout & Flare (EU045A and EU045B) (EP009)	CE009	-	-	0.01	-	-	negl.	0.16	-	-	0.02	0.19
Fire Pump (EU034) (EP006)	N/A	4.03E-04	4.86E-05	4.90E-04	-	-	6.20E-04	-	-	-	2.15E-04	2.08E-03
Biomethanator Flare (EU048) (EP013)	CE013						**see note					
Space Heaters	N/A	-	-	negl.	-	-	negl.	0.02	-	-	negl.	0.02
Total Existing Emission Units	-	**9.85**	**2.56**	**0.01**	**0.00**	**0.00**	**2.46**	**1.96**	**2.56**	**0.00**	**0.02**	**11.99**
Proposed Modification												
Boiler #1 (EU081) (EP020) & Boiler #2 (EU082) (EP021)	N/A	-	-	negl.	-	-	0.03	0.74	-	-	negl.	0.78
Non-Fuel Grade Ethanol Loadout Skids & Flare (EU083 & EU084) (EP019)	CE019	-	-	negl.	-	-	negl.	0.09	-	-	negl.	0.09
Total Proposed Emission Units	-	**0.00**	**0.00**	**negl.**	**0.00**	**0.00**	**0.03**	**0.83**	**0.00**	**0.00**	**negl.**	**0.87**
Proposed Modification - Pneumatic Conveyance System												
Fork Truck Unloading Area (EU075)	CE016	-	-	-	-	-	-	-	-	-	-	-
	CE022	-	-	-	-	-	-	-	-	-	-	-
Total Proposed Emission Units	-	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
SOURCE TOTAL (PSD Applicability)	-	**9.85**	**2.56**	**0.01**	**0.00**	**0.00**	**2.49**	**2.79**	**2.56**	**0.00**	**0.02**	**12.87**
Fugitive Emissions												
Uncaptured Emissions From Grain Receiving (F001)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Truck Traffic - EPCO Plant (F002)	N/A	-	-	-	-	-	-	-	-	-	-	-
Equipment Leaks (F003)	N/A	negl.	-	0.03	-	-	-	0.66	negl.	-	0.07	0.78
Cooling Tower (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Cooling Tower - EPCO Plant (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Corn Oil Storage (EU061 and EU062) (F005)	N/A	negl.	negl.	-	-	-	negl.	-	0.06	-	-	0.29
Storage Tanks (T001 - T010)	N/A	-	-	-	-	-	-	-	-	-	-	-
Total Existing Fugitives	-	**negl.**	**negl.**	**0.03**	**0.00**	**0.00**	**negl.**	**0.66**	**0.06**	**0.00**	**0.07**	**1.07**
Proposed Modification												
Equipment Leaks - NonFuel Grade Ethanol Distillation Process (F003)	N/A	2.64E-03	-	0.01	-	-	-	0.17	negl.	-	0.02	0.20
Cooling Tower - NonFuel Grade Ethanol Distillation Process (F004)	N/A	-	-	-	-	-	-	-	-	-	-	-
Storage Tanks (T013 - T017) (a)	N/A	-	-	1.95	1.95	1.95	-	-	-	1.95	1.95	3.85
Total Proposed Fugitives	-	**2.64E-03**	**0.00**	**1.96**	**1.95**	**1.95**	**0.00**	**0.17**	**negl.**	**1.95**	**1.97**	**4.05**
SOURCE TOTAL (FUGITIVES)	-	**2.64E-03**	**0.00**	**1.99**	**1.95**	**1.95**	**0.00**	**0.83**	**0.06**	**1.95**	**2.03**	**5.12**
SOURCE TOTAL (Part 70 Applicability)	-	**9.85**	**2.56**	**2.00**	**1.95**	**1.95**	**2.49**	**3.62**	**2.62**	**1.95**	**2.05**	**17.99**

Notes:
(a) The potential HAPs from the tanks will be limited to any one of these HAPs or a combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl idobutyl ketone, and toluene.
Non-HAP fugitive emissions are not counted toward the determination of Part 70, PSD, or Emission Offset applicability.
HAP fugitive emissions are counted only toward the determination of Part 70 applicability.
* The acrolein, formaldehyde, and methanol individual HAP limits are based on the total HAP limit of 2.32 tons per year.
** The biomethanator flare only operates when the DDGS dryers are down. The operation of the DDGS dryers is the worst case scenario for emissions, and the emissions from the DDGS dryers have been included in the total PTE.

Appendix A: Emission Calculations
Natural Gas HAPs Combustion Emissions Summary
Existing Emission Units

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

	Emission	TO / HRSG		Dryers (2 @ 45)		Loadout Flare (CE009)		Biomethanator Flare		Space Heaters		EPCO Heaters	
	Factor	135.0 MMBtu/hr		90.0 MMBtu/hr		10.0 MMBtu/hr		6 MMBtu/hr		2.5 MMBtu/hr		0.62 MMBtu/hr	
Pollutant	(lb/MMBtu)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
2-Methylnaphthalene	2.40E-08	3.24E-06	1.42E-05	2.16E-06	9.46E-06	2.40E-07	1.05E-06	1.44E-07	6.31E-07	6.00E-08	2.63E-07	1.49E-08	6.52E-08
3-Methylchloranthrene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
7,12-Dimethylbenz(a)anthracene	1.60E-08	2.16E-06	9.46E-06	1.44E-06	6.31E-06	1.60E-07	7.01E-07	9.60E-08	4.20E-07	4.00E-08	1.75E-07	9.92E-09	4.34E-08
Acenaphthene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Acenaphthlyene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Anthracene	2.40E-09	3.24E-07	1.42E-06	2.16E-07	9.46E-07	2.40E-08	1.05E-07	1.44E-08	6.31E-08	6.00E-09	2.63E-08	1.49E-09	6.52E-09
Benz(a)anthracene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Benzene	2.10E-06	2.84E-04	1.24E-03	1.89E-04	8.28E-04	2.10E-05	9.20E-05	1.26E-05	5.52E-05	5.25E-06	2.30E-05	1.30E-06	5.70E-06
Benzo(a)pyrene	1.20E-09	1.62E-07	7.10E-07	1.08E-07	4.73E-07	1.20E-08	5.26E-08	7.20E-09	3.15E-08	3.00E-09	1.31E-08	7.44E-10	3.26E-09
Benzo(b)fluoranthene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Benzo(g,h,i)perylene	1.20E-09	1.62E-07	7.10E-07	1.08E-07	4.73E-07	1.20E-08	5.26E-08	7.20E-09	3.15E-08	3.00E-09	1.31E-08	7.44E-10	3.26E-09
Benzo(k)fluoranthene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Chrysene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Dibenzo(a,h)anthracene	1.20E-09	1.62E-07	7.10E-07	1.08E-07	4.73E-07	1.20E-08	5.26E-08	7.20E-09	3.15E-08	3.00E-09	1.31E-08	7.44E-10	3.26E-09
Dichlorobenzene	1.20E-06	1.62E-04	7.10E-04	1.08E-04	4.73E-04	1.20E-05	5.26E-05	7.20E-06	3.15E-05	3.00E-06	1.31E-05	7.44E-07	3.26E-06
Fluoranthene	3.00E-09	4.05E-07	1.77E-06	2.70E-07	1.18E-06	3.00E-08	1.31E-07	1.80E-08	7.88E-08	7.50E-09	3.29E-08	1.86E-09	8.15E-09
Fluorene	2.80E-09	3.78E-07	1.66E-06	2.52E-07	1.10E-06	2.80E-08	1.23E-07	1.68E-08	7.36E-08	7.00E-09	3.07E-08	1.74E-09	7.60E-09
Formaldehyde	7.50E-05	1.01E-02	4.43E-02	6.75E-03	2.96E-02	7.50E-04	3.29E-03	4.50E-04	1.97E-03	1.88E-04	8.21E-04	4.65E-05	2.04E-04
Hexane	1.80E-03	2.43E-01	1.06E+00	1.62E-01	7.10E-01	1.80E-02	7.88E-02	1.08E-02	4.73E-02	4.50E-03	1.97E-02	1.12E-03	4.89E-03
Indeno(1,2,3-cd)pyrene	1.80E-09	2.43E-07	1.06E-06	1.62E-07	7.10E-07	1.80E-08	7.88E-08	1.08E-08	4.73E-08	4.50E-09	1.97E-08	1.12E-09	4.89E-09
Napthalene	6.10E-07	8.24E-05	3.61E-04	5.49E-05	2.40E-04	6.10E-06	2.67E-05	3.66E-06	1.60E-05	1.53E-06	6.68E-06	3.78E-07	1.66E-06
Phenanathrene	1.70E-08	2.30E-06	1.01E-05	1.53E-06	6.70E-06	1.70E-07	7.45E-07	1.02E-07	4.47E-07	4.25E-08	1.86E-07	1.05E-08	4.62E-08
Pyrene	5.00E-09	6.75E-07	2.96E-06	4.50E-07	1.97E-06	5.00E-08	2.19E-07	3.00E-08	1.31E-07	1.25E-08	5.48E-08	3.10E-09	1.36E-08
Toluene	3.40E-06	4.59E-04	2.01E-03	3.06E-04	1.34E-03	3.40E-05	1.49E-04	2.04E-05	8.94E-05	8.50E-06	3.72E-05	2.11E-06	9.23E-06
Arsenic	2.40E-07	3.24E-05	1.42E-04	2.16E-05	9.46E-05	2.40E-06	1.05E-05	1.44E-06	6.31E-06	6.00E-07	2.63E-06	1.49E-07	6.52E-07
Cadmium	1.10E-06	1.49E-04	6.50E-04	9.90E-05	4.34E-04	1.10E-05	4.82E-05	6.60E-06	2.89E-05	2.75E-06	1.20E-05	6.82E-07	2.99E-06
Chromium	1.40E-06	1.89E-04	8.28E-04	1.26E-04	5.52E-04	1.40E-05	6.13E-05	8.40E-06	3.68E-05	3.50E-06	1.53E-05	8.68E-07	3.80E-06
Cobalt	8.40E-08	1.13E-05	4.97E-05	7.56E-06	3.31E-05	8.40E-07	3.68E-06	5.04E-07	2.21E-06	2.10E-07	9.20E-07	5.21E-08	2.28E-07
Manganese	3.80E-07	5.13E-05	2.25E-04	3.42E-05	1.50E-04	3.80E-06	1.66E-05	2.28E-06	9.99E-06	9.50E-07	4.16E-06	2.36E-07	1.03E-06
Mercury	2.60E-07	3.51E-05	1.54E-04	2.34E-05	1.02E-04	2.60E-06	1.14E-05	1.56E-06	6.83E-06	6.50E-07	2.85E-06	1.61E-07	7.06E-07
Nickel	2.10E-05	2.84E-03	1.24E-02	1.89E-03	8.28E-03	2.10E-04	9.20E-04	1.26E-04	5.52E-04	5.25E-05	2.30E-04	1.30E-05	5.70E-05
TOTAL		**0.26**	**1.13**	**0.17**	**0.75**	**0.02**	**0.08**	**0.01**	**0.05**	**0.005**	**0.02**	**0.001**	**0.01**

Total Combustion Emissions (tons/yr) 2.04

Notes:
Emission factors are from AP-42, 5th Edition, Section 1.4, "Natural Gas Combustion," 7/98.

Methodology:
Emissions (lb/hr) = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu)
Emissions (tons/yr) = Emissions (lb/hr) * 8760 hr/yr ÷ 2,000 lb/ton

Appendix A: Emission Calculations
Natural Gas HAPs Combustion Emissions Summary
Proposed Emission Units

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Pollutant	Emission Factor (lb/MMBtu)	Boilers (2 @ 48.16) 96.32 MMBtu/hr (lb/hr)	Boilers (2 @ 48.16) 96.32 MMBtu/hr (tons/yr)	Loadout Flare (CE019) 10.0 MMBtu/hr (lb/hr)	Loadout Flare (CE019) 10.0 MMBtu/hr (tons/yr)
2-Methylnaphthalene	2.35E-08	2.27E-06	9.93E-06	2.35E-07	1.03E-06
3-Methylchloranthrene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
7,12-Dimethylbenz(a)anthracene	1.57E-08	1.51E-06	6.62E-06	1.57E-07	6.87E-07
Acenaphthene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Acenaphthlyene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Anthracene	2.35E-09	2.27E-07	9.93E-07	2.35E-08	1.03E-07
Benz(a)anthracene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Benzene	2.06E-06	1.98E-04	8.69E-04	2.06E-05	9.02E-05
Benzo(a)pyrene	1.18E-09	1.13E-07	4.96E-07	1.18E-08	5.15E-08
Benzo(b)fluoranthene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Benzo(g,h,i)perylene	1.18E-09	1.13E-07	4.96E-07	1.18E-08	5.15E-08
Benzo(k)fluoranthene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Chrysene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Dibenzo(a,h)anthracene	1.18E-09	1.13E-07	4.96E-07	1.18E-08	5.15E-08
Dichlorobenzene	1.18E-06	1.13E-04	4.96E-04	1.18E-05	5.15E-05
Fluoranthene	2.94E-09	2.83E-07	1.24E-06	2.94E-08	1.29E-07
Fluorene	2.75E-09	2.64E-07	1.16E-06	2.75E-08	1.20E-07
Formaldehyde	7.35E-05	7.08E-03	3.10E-02	7.35E-04	3.22E-03
Hexane	1.76E-03	1.70E-01	7.44E-01	1.76E-02	7.73E-02
Indeno(1,2,3-cd)pyrene	1.76E-09	1.70E-07	7.44E-07	1.76E-08	7.73E-08
Napthalene	5.98E-07	5.76E-05	2.52E-04	5.98E-06	2.62E-05
Phenanathrene	1.67E-08	1.61E-06	7.03E-06	1.67E-07	7.30E-07
Pyrene	4.90E-09	4.72E-07	2.07E-06	4.90E-08	2.15E-07
Toluene	3.33E-06	3.21E-04	1.41E-03	3.33E-05	1.46E-04
Arsenic	1.96E-07	1.89E-05	8.27E-05	1.96E-06	8.59E-06
Beryllium	1.18E-08	1.13E-06	4.96E-06	1.18E-07	5.15E-07
Cadmium	1.08E-06	1.04E-04	4.55E-04	1.08E-05	4.72E-05
Chromium	1.37E-06	1.32E-04	5.79E-04	1.37E-05	6.01E-05
Cobalt	8.24E-08	7.93E-06	3.47E-05	8.24E-07	3.61E-06
Manganese	3.73E-07	3.59E-05	1.57E-04	3.73E-06	1.63E-05
Mercury	2.55E-07	2.46E-05	1.08E-04	2.55E-06	1.12E-05
Nickel	2.06E-06	1.98E-04	8.69E-04	2.06E-05	9.02E-05
Selenium	2.35E-08	2.27E-06	9.93E-06	2.35E-07	1.03E-06
TOTAL		0.18	0.78	0.02	0.08

Total Combustion Emissions (tons/yr) **0.86**

Notes:
Emission factors are from AP-42, 5th Edition, Section 1.4, "Natural Gas Combustion," 7/98.

Methodology:
Emissions (lb/hr) = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu)
Emissions (tons/yr) = Emissions (lb/hr) * 8760 hr/yr ÷ 2,000 lb/ton

Appendix A: Emission Calculations
Grain Receiving and Handling, Hammermilling, & DDGS Handling Operations

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Potential to Emit $PM/PM_{10}/PM_{2.5}$ - Captured Emissions

Baghouse ID	Process Description	Outlet Grain Loading (gr/dscf)	Maximum Air Flow Rate (scfm)	PTE of PM/PM_{10} After Control (lb/hr)	PTE of PM/PM_{10} After Control (tons/yr)	PTE of $PM_{2.5}$ After Control (lb/hr)	PTE of $PM_{2.5}$ After Control (tons/yr)	Control Efficiency (%)	PTE of PM/PM_{10} Before Control (lb/hr)	PTE of PM/PM_{10} Before Control (tons/yr)	PTE of $PM_{2.5}$ Before Control (lb/hr)	PTE of $PM_{2.5}$ Before Control (tons/yr)	Limited PTE of $PM/PM_{10}/PM_{2.5}$ (lb/hr)	Limited PTE of $PM/PM_{10}/PM_{2.5}$ (tons/yr)
CE001	Grain Receiving and Handling (EU001 - EU007, EU064)	0.005	39,000	1.67	7.32	0.28	1.24	99%	167.14	732.09	28.41	124.45	1.67	7.31
CE003	Hammermills (EU010, EU011, EU067)	0.005	28,000	1.20	5.26	0.20	0.89	99%	120.00	525.60	20.40	89.35	1.20	5.26
CE008	DDGS Handling and Loadout (EU040 - EU043)	0.005	3,750	0.16	0.70	0.03	0.12	99%	16.07	70.39	2.73	11.97	0.16	0.70

Allowable Emissions:
The following calculations determine PM compliance with 326 IAC 6-3-2 for process weight rates greater than 30 tons per hour:

Grain Receiving and Handling (EU001 - EU005, EU064):
P = 420 tons/hr
limit = 55.0 x (420 ^0.11) - 40 = 66.9 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITH controls.

Grain Receiving and Handling (EU006, EU007):
Hammermills (EU010, EU011, EU067):
P = 140 tons/hr
limit = 55.0 x (140 ^0.11) - 40 = 54.7 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITH controls.

DDGS Handling and Loadout (EU040 - EU043):
P = 101 tons/hr
limit = 55.0 x (101 ^0.11) - 40 = 51.4 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITHOUT controls.

Notes:
Assume all PM emissions equal PM_{10} emissions.
Assume controlled $PM_{2.5}$ emissions equal 17% PM/PM_{10} emissions (AP-42 Table 9.9.1-1, Reference 40).
The limited PTE emission limits have been established in order to render 326 IAC 2-2 (PSD) not applicable.

Methodology:
PTE of PM/PM_{10} After Control (lb/hr) = Grain Loading (gr/dscf) * Max. Air Flow Rate (scfm) * 60 min/hr ÷ 7000 lb/gr
PTE of PM/PM_{10} After Control (tons/yr) = PTE of PM/PM_{10} After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE of $PM_{2.5}$ After Control (lb/hr) = PTE of PM/PM_{10} After Control (lb/hr) * 0.17
PTE of $PM_{2.5}$ After Control (tons/yr) = PTE of $PM_{2.5}$ After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE Before Control (lb/hr) = PTE After Control (lb/hr) ÷ (1 - Control Efficiency)
PTE Before Control (tons/yr) = PTE After Control (tons/yr) ÷ (1 - Control Efficiency)
Limited PTE of $PM/PM_{10}/PM_{2.5}$ (tons/yr) = Limited PTE of PM/PM_{10} (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

2. Potential to Emit $PM/PM_{10}/PM_{2.5}$ - Fugitive Emissions:

Unit ID	Unit Description	Annual Throughput Limit (tons/yr)	Uncontrolled PM Emission Factor (lb/ton)	Uncontrolled $PM_{10}/PM_{2.5}$ Emission Factor (lb/ton)	Baghouse ID	Capture Efficiency (%)	Fugitive PM Emissions (tons/yr)	Fugitive $PM_{10}/PM_{2.5}$ Emissions (tons/yr)
EU001	Grain Receiving	646,800	0.035	0.0078	CE001	80%	2.26	0.50

Notes:
Emission factors are from AP-42, Chapter 9.9.1-1 and AP-42, Chapter 9.9.1-2. Assume all the grain receiving and loadout is by hopper truck, which is the worst case scenario.
Assume all $PM_{2.5}$ emissions equal to PM_{10} emissions.

Methodology:
Fugitive Emissions (tons/yr) = Annual Throughput Limit (tons/yr) * Uncontrolled Emission Factor (lb/ton) * (1 - Capture Efficiency) ÷ 2000 lb/ton

Appendix A: Emission Calculations
DDGS Cooler

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Potential to Emit PM/PM_{10}/$PM_{2.5}$

Baghouse ID	Process Description	Control Device	Outlet Grain Loading (gr/dscf)	Maximum Air Flow Rate (scfm)	PTE of PM/PM_{10} After Control (lb/hr)	PTE of PM/PM_{10} After Control (tons/yr)	PTE of $PM_{2.5}$ After Control (lb/hr)	PTE of $PM_{2.5}$ After Control (tons/yr)	Control Efficiency (%)	PTE of PM/PM_{10} Before Control (lb/hr)	PTE of PM/PM_{10} Before Control (tons/yr)	PTE of $PM_{2.5}$ Before Control (lb/hr)	PTE of $PM_{2.5}$ Before Control (tons/yr)	Limited PTE of PM/PM_{10}/$PM_{2.5}$ (lb/hr)	Limited PTE of PM/PM_{10}/$PM_{2.5}$ (tons/yr)
CE014	DDGS Cooler	Baghouse	0.002	30,299	0.52	2.28	0.09	0.39	99%	51.94	227.50	8.83	38.68	0.94	4.12

Allowable Emissions:
The following calculations determine PM compliance with 326 IAC 6-3-2 for process weight rates greater than 30 tons per hour:

P = 34 tons/hr
limit = 55.0 x (34 ^0.11) - 40 = 41.1 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITH controls.

Notes:
Assume all PM emissions equal PM_{10} emissions.
Assume controlled $PM_{2.5}$ emissions equal 17% PM/PM_{10} emissions (AP-42 Table 9.9.1-1, Reference 40).
The limited PTE emission limits have been established in order to render 326 IAC 2-2 (PSD) not applicable.

Methodology:
PTE of PM/PM_{10} After Control (lb/hr) = Grain Loading (gr/dscf) * Max. Air Flow Rate (scfm) * 60 min/hr ÷ 7000 lb/gr
PTE of PM/PM_{10} After Control (tons/yr) = PTE of PM/PM_{10} After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE of $PM_{2.5}$ After Control (lb/hr) = PTE of PM/PM_{10} After Control (lb/hr) * 0.17
PTE of $PM_{2.5}$ After Control (tons/yr) = PTE of $PM_{2.5}$ After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (lb/hr) = PTE of PM/PM_{10} After Control (lb/hr) ÷ (1 - Control Efficiency)
PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (tons/yr) = PTE of PM/PM_{10} After Control (tons/yr) ÷ (1 - Control Efficiency)
Limited PTE of PM/PM_{10}/$PM_{2.5}$ (tons/yr) = Limited PTE of PM/PM_{10} (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

2. Potential to Emit VOC:

Maximum DDGS Production: 297,840 tons/yr = 34 tons/hr
Limited DDGS Production: 210,000 tons/yr
VOC Emission Factor: 0.065 lbs/ton of DDGS (based on November 2007 stack testing)

Unlimited PTE of VOC (tons/yr) = 297,840 tons/yr * 0.065 lbs/ton ÷ 2000 lb/ton = 9.68 tons/yr
Limited PTE of VOC (tons/yr) = 210,000 tons/yr * 0.065 lbs/ton ÷ 2000 lb/ton = 6.83 tons/yr

3. Potential to Emit HAPs:

	Uncontrolled					Limited
	Acetaldehyde	Acrolein	Formaldehyde	Methanol	Total HAPs	Acetaldehyde
Emission Rate (lb/hr) *	7.50E-02	1.50E-02	1.50E-02	1.50E-02	0.12	7.50E-02
Potential to Emit (tons/yr)	0.33	0.07	0.07	0.07	0.53	0.33

* HAP emission rates were estimated by the source based on the stack testing results from a similar engineered site (Glacial Lakes Energy, MN) and scaled linearly based on production capacity.

Methodology:
Potential to Emit (tons/yr) = Emission Rate (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

Appendix A: Emission Calculations
Corn Storage Bin EU066

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Corn Storage Bin EU066 - No Control

Max Throughput (tons/hr)	PM Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	$PM_{2.5}$ Emission Factor (lb/ton)	PM Emissions		PM_{10} Emisssions		$PM_{2.5}$ Emisssions	
				lb/hr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr
420	0.035	0.0078	0.001326	14.70	64.39	3.28	14.35	0.56	2.44

Allowable Emissions:
The following calculations determine PM compliance with 326 IAC 6-3-2 for process weight rates greater than 30 tons per hour:

P = 420 tons/hr
limit = 55.0 x (420 ^0.11) - 40 = 66.9 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITHOUT controls.

Notes:
Emission factors are from AP-42, Chapter 9.9.1-1.
Assume $PM_{2.5}$ emissions equal 17% PM_{10} emissions (AP-42 Table 9.9.1-1, Reference 40).

Methodology:
PM Emissions (lb/hr) = Max Throughput (tons/hr) * PM Emission Factor (lbs/ton)
PM Emissions (tons/yr) = PM Emissions (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PM_{10} Emissions (lb/hr) = Max Throughput (tons/hr) * PM_{10} Emission Factor (lbs/ton)
PM_{10} Emissions (tons/yr) = PM_{10} Emissions (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

Appendix A: Emission Calculations
Receiving and Transfer Operations

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Potential to Emit PM/PM_{10}/$PM_{2.5}$ - Captured Emissions:

Process Description	Baghouse ID	Outlet Grain Loading (gr/dscf)**	Maximum Air Flow Rate (scfm)**	PTE of PM/PM_{10} After Control (lb/hr)	PTE of PM/PM_{10} After Control (tons/yr)	PTE of $PM_{2.5}$ After Control (lb/hr)	PTE of $PM_{2.5}$ After Control (tons/yr)	Control Efficiency (%)	PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (lb/hr)	PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (tons/yr)
Truck & Railcar Unloading Areas (EU070 & EU073) & Storage Bins (EU076 & EU077)	CE015	0.0000295	3,200	0.0008	0.0035	0.0001	0.0006	99.9%	0.81	3.54
Fork Truck Unloading Area (EU075)	CE016	0.0000295	2,500	0.0006	0.0028	0.0001	0.0005	99.9%	0.63	2.77
	CE022	0.0000295	22,500	0.0057	0.0249	0.0010	0.0042	99.9%	5.69	24.92
Process Feed Area Surge Hoppers (EU078 & EU079)	CE017	0.0000295	1,300	0.0003	0.0014	0.0001	0.0002	99.9%	0.33	1.44
Truck Unloading Area (EU080)	CE018	0.0000295	760	0.0002	0.0008	0.00003	0.0001	99.9%	0.19	0.84

** Specifications of the control devices provided by the source.

Allowable Emissions:
The following calculations determine PM compliance with 326 IAC 6-3-2 for process weight rates less than 30 tons per hour:

P = 25 tons/hr
limit = 4.1 x (25 ^0.67) = 35.4 lb/hr PM

Each unit is capable of complying with 326 IAC 6-3-2 WITHOUT controls.

Notes:
The raw material handled and transferred has been requested by the source as confidential information.
Assume all PM emissions equal PM_{10} emissions.
Assume controlled $PM_{2.5}$ emissions equal 17% PM/PM_{10} emissions (AP-42 Table 9.9.1-1, Reference 40).

Methodology:
PTE of PM/PM_{10} After Control (lb/hr) = Grain Loading (gr/dscf) * Max. Air Flow Rate (scfm) * 60 min/hr ÷ 7000 lb/gr
PTE of PM/PM_{10} After Control (tons/yr) = PTE of PM/PM_{10} After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE of $PM_{2.5}$ After Control (lb/hr) = PTE of PM/PM_{10} After Control (lb/hr) * 0.17
PTE of $PM_{2.5}$ After Control (tons/yr) = PTE of $PM_{2.5}$ After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (lb/hr) = PTE of PM/PM_{10} After Control (lb/hr) ÷ (1 - Control Efficiency)
PTE of PM/PM_{10}/$PM_{2.5}$ Before Control (tons/yr) = PTE of PM/PM_{10} After Control (tons/yr) ÷ (1 - Control Efficiency)

Appendix A: Emission Calculations
Fermentation Scrubber CE005
Emission Units EU016 through EU020

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Scrubber VOC Control Efficiency = 99.60%
Scrubber HAP Control Efficiency = 50.00%

Controlled Emissions	lb/hr	tons/yr
VOC	1.31	5.74
Acetaldehyde	0.03	0.13
Acrolein	0.01	0.04
Formaldehyde	0.004	0.02
Methanol	0.01	0.04
Total HAPs (Controlled)	0.054	0.24

Uncontrolled Emissions	lb/hr	tons/yr
VOC	327.50	1,434.45
Acetaldehyde	0.06	0.26
Acrolein	0.02	0.09
Formaldehyde	0.008	0.04
Methanol	0.02	0.09
Total HAPs (Uncontrolled)	0.108	0.47

Limited Emissions	lb/hr	tons/yr
VOC	9.50	41.61
Acetaldehyde	1.88	8.23
Acrolein	0.02	0.09
Formaldehyde	0.008	0.04
Methanol	0.02	0.09
Total HAPs (Limited)	1.91	8.37

Notes:
Controlled VOC and acetaldehyde emission rates and VOC control efficiency are based on performance tests performed on April 8, 2009.
Controlled acrolein, methanol, and formaldehyde emission rates are based on performance tests at similar facilities.
The limited PTE emission limits for VOC, acetaldehyde, and total HAPs have been established in order to render 326 IAC 2-2 (PSD) not applicable.

Methodology:
Controlled Emissions (tons/yr) = Controlled Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton
Uncontrolled Emissions (lb/hr) = Controlled Emissions (lb/hr) ÷ (1 - Control Efficiency)
Uncontrolled Emissions (tons/yr) = Uncontrolled Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton
Limited Emissions (tons/yr) = Limited Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton

Appendix A: Emission Calculations
Fermentation Scrubber CE010
Emission Units EU016 through EU020

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Scrubber VOC Control Efficiency = 99.96%
Scrubber HAP Control Efficiency = 50.00%

Controlled Emissions	lb/hr	tons/yr
VOC	0.009	0.04
Acetaldehyde	0.0002	0.001
Acrolein	0.01	0.04
Formaldehyde	0.004	0.02
Methanol	0.01	0.04
Total HAPs (Controlled)	0.024	0.11

Uncontrolled Emissions	lb/hr	tons/yr
VOC	22.50	98.55
Acetaldehyde	0.0004	0.002
Acrolein	0.02	0.09
Formaldehyde	0.008	0.04
Methanol	0.02	0.09
Total HAPs (Uncontrolled)	0.048	0.21

Limited Emissions	lb/hr	tons/yr
VOC	0.62	2.72
Acetaldehyde	0.114	0.50
Acrolein	0.02	0.09
Formaldehyde	0.008	0.04
Methanol	0.02	0.09
Total HAPs (Limited)	0.13	0.57

Notes:
Controlled VOC and acetaldehyde emission rates and VOC control efficiency are based on performance tests performed on April 8, 2009.
Controlled acrolein, methanol, and formaldehyde emission rates are based on performance tests at similar facilities.
The limited PTE emission limits for VOC, acetaldehyde, and total HAPs have been established in order to render 326 IAC 2-2 (PSD) not applicable.

Methodology:
Controlled Emissions (tons/yr) = Controlled Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton
Uncontrolled Emissions (lb/hr) = Controlled Emissions (lb/hr) ÷ (1 - Control Efficiency)
Uncontrolled Emissions (tons/yr) = Uncontrolled Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton
Limited Emissions (tons/yr) = Limited Emissions (lb/hr) * 8760 hrs/yr ÷ 2000 lb/ton

Appendix A: Emission Calculations
DDGS Dryers and TO/HRSG
Combustion Emissions

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. DDGS Dryers Combustion Emissions

Heat Input Capacity (MMBtu/hr)	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
90.0	1020	772.94

	PM*	PM_{10}*	direct $PM_{2.5}$*	SO_2	NO_x**	VOC	CO
Emission Factor (lb/MMCF)	1.9	7.6	7.6	0.6	81.7	5.5	84
Potential Emissions (tons/yr)	0.73	2.94	2.94	0.23	31.57	2.13	32.46

* PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined.
$PM_{2.5}$ emission factor is filterable and condensable $PM_{2.5}$ combined.
** NO_x emission factor based on stack test results from a similar source. Central Indiana Ethanol, LLC will verify emission rate via stack test.

2. TO / HRSG Combustion Emissions

Heat Input Capacity (MMBtu/hr)	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
135.0	1020	1,159.41

	PM*	PM_{10}*	direct $PM_{2.5}$*	SO_2	NO_x**	VOC	CO
Emission Factor (lb/MMCF)	1.9	7.6	7.6	0.6	80	5.5	84
Potential Emissions (tons/yr)	1.10	4.41	4.41	0.35	46.38	3.19	48.70

* PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined.
$PM_{2.5}$ emission factor is filterable and condensable $PM_{2.5}$ combined.
** NO_x emission factor based on stack test results from a similar source. Central Indiana Ethanol, LLC will verify emission rate via stack test.

Notes:
Emission factors are from AP-42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3 (AP-42, 3/98).
Assume $PM_{2.5}$ emissions equal to PM_{10} emissions.
HAP emissions are included on the HAPs Combutions Emissions Summary sheet.

Methodology:
Potential Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF) ÷ 2000 lb/ton

3. Combined Combustion Emissions - GHGs

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	115,941	2.22	2.13
Summed Potential Emissions (tons/yr)	115,946		
CO_2e Total (tons/yr)	116,647		

Notes:
The N_2O Emission Factor for uncontrolled is 2.2. The N_2O Emission Factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Potential Emissions (tons/yr) = Combined Throughput (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emission Calculations
DDGS Dryers and TO/HRSG
Process Emissions

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

4. Process Emissions

Particulate Emissions

Control ID	Emissions Units	Outlet Grain Loading (gr/dscf)	Maximum Air Flow Rate (scfm)	PTE of $PM/PM_{10}/PM_{2.5}$ After Control (lb/hr)	PTE of $PM/PM_{10}/PM_{2.5}$ After Control (tons/yr)	Control Efficiency (%)	PTE of $PM/PM_{10}/PM_{2.5}$ Before Control (lb/hr)	PTE of $PM/PM_{10}/PM_{2.5}$ Before Control (tons/yr)
CE006 / CE007	EU035, EU056	0.0137	33,360	3.92	17.16	90%	39.17	171.58

Allowable Emissions:
The following calculations determine PM compliance with 326 IAC 6-3-2 for process weight rates greater than 30 tons per hour:

P = 34 tons/hr
limit = 55.0 x (34 ^0.11) - 40 = 41.1 lb/hr PM

This unit is capable of complying with 326 IAC 6-3-2 WITHOUT controls.

Notes:
The $PM/PM_{10}/PM_{2.5}$ outlet grain loading is based on November 2007 stack test results.

Methodology:
PTE After Control (lb/hr) = Grain Loading (gr/dscf) * Max. Air Flow Rate (scfm) * 60 min/hr ÷ 7000 lb/gr
PTE After Control (tons/yr) = PTE After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE Before Control (lb/hr) = PTE After Control (lb/hr) ÷ (1 - Control Efficiency)
PTE Before Control (tons/yr) = PTE Before Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

CO, VOC, HAP, and NO_x Emissions

Control ID	Pollutant	PTE After Control		Control Efficiency (%)	PTE Before Control	
		lb/hr	tons/yr		lb/hr	tons/yr
CE007	CO	13.99	61.28	90.0%	139.90	612.76
	VOC	1.09	4.77	99.62%	286.84	1,256.37
	Acetaldehyde	0.14	0.61	90%	1.40	6.13
	Acrolein	0.09	0.39	90%	0.90	3.94
	Formaldehyde	0.10	0.44	90%	1.00	4.38
	Methanol	0.07	0.31	90%	0.70	3.07
	Total HAPs	0.81	3.55	90%	8.10	35.48
	NO_x	9.64	42.22	---	---	---

Notes:
The CO and NO_x emission rates after controls are based on November 2007 stack test results.
The VOC and HAP after control (lb/hr) emission rates for the RTO are based on emission rates observed during the November 2007 stack test results.

Methodology:
PTE After Control (tons/yr) = PTE After Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
PTE Before Control (lb/hr) = PTE After Control (lb/hr) ÷ (1 - Control Efficiency)
PTE Before Control (tons/yr) = PTE Before Control (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

SO_2 Emissions

Unlimited Ethanol Production - Railcar Loading (gal/min)	Emission Factor (lb/gal)	Unlimited Emission Rate (lb/hr)	Unlimited Emission Rate (tons/yr)	Controlled Emission Rate (lb/hr)	Controlled Emission Rate (tons/yr)	Limited Ethanol Production (gal/yr)	Emission Factor (lb/gal)	Limited Emission Rate (lb/hr)	Limited Emission Rate (tons/yr)
800	0.001	48.00	210.24	0.29	1.27	64,900,000	0.001	7.41	32.45

Notes:
SO_2 emission factor based on testing at similar plant.
SO_2 emission rate after controls is based on November 2007 stack test results.

Methodology:
Unlimited Emission Rate (lb/hr) = Unlimited Production (gal/min) * Emission Factor (lb/gal) * 60 min/hr
Limited Emission Rate (lb/hr) = Limited Production (gal/yr) * Emission Factor (lb/gal) ÷ 8760 hr/yr
Emission Rate (tons/yr) = Emission Rate (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

5. Combined Limited Emissions

Pollutant	Limited Emissions (lb/hr)	Limited Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	8.0	35.04
VOC	5.15	22.56
CO	21.0	91.98
SO_2	8.5	37.23
NO_x	19.7	86.29
Acetaldehyde	0.18	0.79
Total HAPs	0.53	2.32

Notes:
The limited PTE emission limits have been established in order to render 326 IAC 2-2 (PSD) not applicable.

Methodology:
Limited Emissions (tons/yr) = Limited Emissions (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

Appendix A: Emission Calculations
Ethanol Loading Racks (EU045A and EU045B)
Uncontrolled Potential to Emit

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Emission Factors: AP-42

Denatured and blended ethanol will be shipped by either truck loading rack EU045A or railcar loading rack EU045B. The railcars and trucks may each be used to carry gasoline prior to filling with ethanol. Both railcars and trucks will be filled by submerged loading process.
Truck loading rack (EU045A) and railcar loading rack (EU045B) will both be controlled by flare CE009 which has a control efficiency of 98% for VOC and HAPs.

According to AP-42, Chapter 5.2 - Transportation and Marketing of Petroleum Liquids (01/95), the VOC emission factors for the truck and rail loading racks can be estimated from the following equation:

$$L = 12.46 \times (SPM)/T$$

where:

L = loading loss (lbs/kgal)
S = a saturation factor (see AP-42, Table 5.2-1)
P = true vapor pressure of the liquid loaded (psia)
M = molecular weight of vapors
T = temperature of the bulk liquid loaded (degree R)

Previous Stored Liquid	*S	P (psia)	M (lb/mole lb)	T (degree R)	L (lb/kgal)
Gasoline (normal)	1.0	6.2	62	512.3	9.35
Gasoline (clean cargo)	0.5	6.2	62	512.3	4.67
Denatured Ethanol (normal)	0.6	0.50	49.7	512.3	0.36
Denatured Ethanol (clean cargo)	0.5	0.50	49.7	512.3	0.30
Blended Ethanol (normal)	0.6	1.54	57.4	512.3	1.29
Blended Ethanol (clean cargo)	0.5	1.54	57.4	512.3	1.07

Note: Blended ethanol based on E70 specifications from TANKS 4.09.

Therefore, the emission factor for loading denatured ethanol to the trucks and railcars which stored gasoline previously
= L (gasoline, normal) - L (gasoline, clean cargo) + L (denatured ethanol, clean cargo) = 4.98 lb/kgal

Therefore, the emission factor for loading blended ethanol to the trucks and railcars which stored gasoline previously
= L (gasoline, normal) - L (gasoline, clean cargo) + L (blended ethanol, clean cargo) = 5.75 lb/kgal

2. Potential to Emit VOC Before Control (assuming all blended ethanol loaded out):

Maximum Loading Rate for EU45A: 36 kgal/hr (for truck loading)
PTE of VOC Before Control (tons/yr) = 36 kgal/hr * 5.75 lbs/gal * 8760 hr/yr ÷ 2000 lb/ton = 906.60 tons/yr

Maximum Loading Rate for EU45B: 48 kgal/hr (for railcar loading)
PTE of VOC Before Control (tons/yr) = 48 kgal/hr * 5.75 lbs/gal * 8760 hr/yr ÷ 2000 lb/ton = 1,208.80 tons/yr

Worst case scenario is when loading all blended ethanol to railcars.	**Worst Case Uncontrolled VOC emissions =**	**1,208.80**	**tons/yr**
Worst case scenario when controlled by flare CE009 with an efficiency of 98%.	**Worst Case Controlled VOC emissions =**	**24.18**	**tons/yr**

Notes:
Blended ethanol has a VOC emission factor of 5.75 lbs/kgal, while denatured ethanol has a VOC emission factor of 4.98.
Therefore the emission factor for blended ethanol was used as a worst case scenario.

Methodology:
Worse Case Controlled VOC Emissions (tons/yr) = Worse Case Uncontrolled VOC Emissions (tons/yr) ÷ (1 - Control Efficiency)

Appendix A: Emission Calculations
Ethanol Loading Racks (EU045A and EU045B)
Limited VOC Emissions
Potential to Emit HAPs

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

3. Limited VOC Emissions:

Annual Denatured and Blended Ethanol Production Limit:	64,900 kgal/yr (for both railcar and truck loading)
Annual Denaturant Limit:	4,900 kgal/yr (for both railcar and truck loading)
Maximum Amount of Blended Ethanol (based on denaturant limit and E70 blend):	16,333 kgal/yr
Flare Control Efficiency:	98%

Different scenarios to determine the worst case scenario:

(1) Assume all blended ethanol is loaded to trucks:
VOC (tons/yr) = 5.75 lbs/kgal * 16,333 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 0.94 tons/yr

(2) Assume all blended ethanol is loaded to dedicated railcars:
VOC (tons/yr) = 1.07 lbs/kgal * 16,333 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 0.18 tons/yr

(3) Assume all denatured ethanol is loaded to trucks:
VOC (tons/yr) = 4.98 lbs/kgal * 64,900 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 3.23 tons/yr

(4) Assume all denatured ethanol is loaded to dedicated railcars:
VOC (tons/yr) = 0.30 lbs/kgal * 64,900 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 0.20 tons/yr

Worst case scenario is when loading all denatured ethanol to trucks.
Truck and Railcar emissions are controlled by enclosed flare CE009. **Worst Case Limited VOC emissions = 3.23 tons/yr**

4. Potential to Emit HAPs:

HAP emissions are mainly from the unloading process for trucks and railcars which may have been used to ship gasoline previously.

HAP	HAP Fraction*	Unlimited PTE of HAP Before Control (tons/yr)	Unlimited PTE of HAP After Control (tons/yr)	Limited PTE of HAP After Control (tons/yr)
Benzene	2.50E-03	3.02	0.06	8.07E-03
Carbon Disulfide	2.00E-05	0.02	4.84E-04	6.46E-05
Cumene	1.00E-04	0.12	2.42E-03	3.23E-04
Ethyl benzene	5.00E-05	0.06	1.21E-03	1.61E-04
n-Hexane	5.00E-02	60.44	1.21	1.61E-01
Toluene	5.00E-03	6.04	0.12	1.61E-02
Xylene	5.00E-04	0.60	0.01	1.61E-03
TOTAL HAPs	---	70.32	1.41	0.19

* This is the HAP fraction for gasoline vapors.

Methodology:
Unlimited PTE of HAP Before Control (tons/yr) = Worse Case VOC Emissions (tons/yr) * HAP Fraction
Unlimited PTE of HAP After Control (tons/yr) = Unlimited PTE of HAP Before Control (tons/yr) * (1 - Control Efficiency)
Limited PTE of HAP After Control (tons/yr) = Worse Case Limited VOC Emissions (tons/yr) * HAP Fraction

Appendix A: Emission Calculations
Ethanol Loading Racks (EU045A and EU045B)
Potential to Emit (NO_x, CO)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

5. Potential to Emit (NO_x and CO) from Flare Combustion (CE009)

Maximum Loadout Rate:	48.00	kgal/hr
Limited Loadout Rate:	64,900	kgal/yr

Pollutant	NO_x	CO
Emission Factor (lb/kgal)	0.077	0.129
Unlimited PTE (tons/yr)	16.19	27.12
Limited PTE (tons/yr)	2.50	4.19

Notes:
Particulate (PM, PM_{10}, and $PM_{2.5}$) and SO_2 emission factors are negligible due to the smokeless design and minimal H_2S levels.
Emission factors for NO_x and CO are based on the information provided by the flare manufacturer (MRW Technologies, Inc.)

Methodology:
Unlimited PTE (tons/yr) = Maximum Loadout Rate (kgal/hr) * Emission Factor (lb/kgal) * 8760 hr/yr ÷ 2000 lb/ton
Limited PTE (tons/yr) = Limited Loadout Rate (kgal/yr) * Emission Factor (lb/kgal) ÷ 2000 lb/ton

6. Potential to Emit (GHGs) from Flare Combustion (CE009)

Heat Input Capacity (MMBtu/hr)	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
10.0	1020	85.88

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	5,153	0.10	0.09
Summed Potential Emissions (tons/yr)	5,153		
CO_2e Total (tons/yr)	5,184		

Notes:
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emission Calculations
Internal Combustion Engines
Diesel Fire Pump

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

A. Emission Factors

Emission factors from NSPS, Subpart IIII (Table 4) for model year 2008 and earlier between 225 and 450 KW (300 and 600 hp)

NO_x + NMHC	10.5 g/kwh =	7.8 g/hp-hr
CO	3.5 g/kwh =	2.6 g/hp-hr
PM	0.54 g/kwh =	0.4 g/hp-hr

Emission factors from AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines, Table 3.3-1 (10-96)

SO_x	0.00205 lb/hp-hr	0.0005125 lb/hp-hr	LSD fuel assume 75% reduction in emissions
PM_{10}	0.00220 lb/hp-hr		
CO_2	1.15 lb/hp-hr		
TOC	0.0025141 lb/hp-hr		

The HAP emission factors are from AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines, Table 3.3-2 (10-96).

B. Limited Emissions

Rated Capacity (hp): 300
Limited Hours of Operation: 500

Pollutant	PM	$PM_{10}/PM_{2.5}$	SO_2	VOC	CO	NO_x	GHGs as CO_2e
Unlimited Emissions (tpy)	0.07	0.17	0.04	0.19	0.43	1.29	86.25
Limited Emissions (tpy)	0.07	0.17	0.04	0.19	0.43	1.29	86.25

C. HAP Emissions

Pollutant	Emission Factor (lb/hp-hr)	Unlimited/ Limited Emissions (tons/yr)
Acetaldehyde	5.37E-06	4.03E-04
Acrolein	6.48E-07	4.86E-05
Benzene	6.53E-06	4.90E-04
1,3-Butadiene	2.74E-07	2.05E-05
Formaldehyde	8.26E-06	6.20E-04
Naphthalene	5.94E-07	4.45E-05
Toluene	2.86E-06	2.15E-04
Xylenes	2.00E-06	1.50E-04
Total PAH HAPs	1.18E-06	8.82E-05
Total HAPs	2.77E-05	2.08E-03

Notes:
Since the fire pump is for emergency use only, the unlimited emissions have been calculated as operating 500 hours per year.
Assume all $PM_{2.5}$ emissions equal to PM_{10} emissions.
Reduction of 75% based upon average fuel sulfur content through year 2005 of 2000 ppm and required use of Low Sulfur Diesel (LSD) with a maximum sulfur content of 500 ppm. EPA 420-R-04-0007: Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines, page 3-91.

Methodology:
Unlimited/Limited Emissions (tons/yr) = Capacity (hp) * Emission Factor (g/hp-hr) * Limited Operation (hr/yr) ÷ 453.54 g/lb ÷ 2000 lb/ton
Unlimited/Limited Emissions (tons/yr) = Capacity (hp) * Emission Factor (lb/hp-hr) * Limited Operation (hr/yr) ÷ 2000 lb/ton

Appendix A: Emission Calculations
Biomethanator Flare CE013

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Max. Heat Input MMBtu/hr	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
6.00	1020	51.53

The methanator flare only operates when the DDGS dryers are down.

	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO	NO_x	HAP
Emission Factor (lb/MMBtu)	-	-	-	-	0.052	0.37	0.068	-
Potential Emissions (tons/yr)	negl.	negl.	negl.	negl.	1.37	9.72	1.79	see note

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	3,092	0.06	0.06
Summed Potential Emissions (tons/yr)	3,092		
CO_2e Total (tons/yr)	3,111		

Notes:
The Permittee stated that particulate emissions from this flare are negligible due to the smokeless design.
The Permittee stated that SO_2 emissions are negligible due to negligible sulfur presence in the gas stream.
Emission factors for NO_x and CO are from AP-42, Chapter 13.5, Table 13.5-1 (01/95).
The emission factor for VOC is derived from the emission factor for THC (0.14 lb/MMBtu) in AP-42, Chapter 13.5, Table 13.5-1 (01/95).
Per Table 13.5-2, the composition of the flare includes 63% non-VOC pollutants (methane and ethane). VOC = 37% * 0.14 = 0.052
HAP emissions are included on the HAPs Combutions Emissions Summary sheet.
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Potential Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Max. Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 hr/yr ÷ 2000 lb/ton
Potential Emissions-GHGs (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emissions Calculations
Natural Gas Combustion Only (MMBtu/hr <100)
Space Heaters

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Max. Heat Input MMBtu/hr	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
2.50	1020	21.47

	Pollutant						
	PM*	PM_{10}*	direct $PM_{2.5}$*	SO_2	NO_x	VOC	CO
Emission Factor (lb/MMCF)	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emissions (tons/yr)	0.02	0.08	0.08	0.01	1.07	0.06	0.90

* PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined.
$PM_{2.5}$ emission factor is filterable and condensable $PM_{2.5}$ combined.
** Emission factors for NO_x: Uncontrolled = 100, Low NO_x Burner = 50, Low NO_x Burners/Flue gas recirculation = 32

Notes:
All emission factors are based on normal firing.
Emission factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
HAP emissions are included on the HAPs Combutions Emissions Summary sheet.

Methodology:
Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Max. Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 hr/yr ÷ 2000 lb/ton

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	1,288	0.02	0.02
Summed Potential Emissions (tons/yr)	1,288		
CO_2e Total (tons/yr)	1,296		

Notes:
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Potential Emissions-GHGs (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emissions Calculations
Natural Gas Combustion Only (MMBtu/hr <100)
Space Heaters (EPCO Plant)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Max. Heat Input MMBtu/hr	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
0.63	1020	5.41

Three (3) heaters @ 210,000 Btu/hr each

	Pollutant						
	PM*	PM_{10}*	direct $PM_{2.5}$*	SO_2	NO_x	VOC	CO
Emission Factor (lb/MMCF)	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emissions (tons/yr)	0.01	0.02	0.02	0.002	0.27	0.01	0.23

* PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined.
$PM_{2.5}$ emission factor is filterable and condensable $PM_{2.5}$ combined.
** Emission factors for NO_x: Uncontrolled = 100, Low NO_x Burner = 50, Low NO_x Burners/Flue gas recirculation = 32

Notes:
All emission factors are based on normal firing.
Emission factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
HAP emissions are included on the HAPs Combutions Emissions Summary sheet.

Methodology:
Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Max. Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 hr/yr ÷ 2000 lb/ton

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	325	0.01	0.01
Summed Potential Emissions (tons/yr)	325		
CO_2e Total (tons/yr)	327		

Notes:
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Potential Emissions-GHGs (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emissions Calculations
Natural Gas Combustion Only (MMBtu/hr <100)
Boilers EU081 & EU082

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Max. Heat Input MMBtu/hr	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
96.32	1020	827.22

Each boiler has a capacity of 48.16 MMBtu/hr.

	Pollutant						
	PM*	PM_{10}*	direct $PM_{2.5}$*	SO_2	NO_x	VOC	CO
Emission Factor (lb/MMCF)	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emissions (tons/yr)	0.79	3.14	3.14	0.25	41.36	2.27	34.74

* PM emission factor is filterable PM only. PM_{10} emission factor is filterable and condensable PM_{10} combined.
$PM_{2.5}$ emission factor is filterable and condensable $PM_{2.5}$ combined.
** Emission factors for NO_x: Uncontrolled = 100, Low NO_x Burner = 50, Low NO_x Burners/Flue gas recirculation = 32

Notes:
All emission factors are based on normal firing.
Emission factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
HAP emissions are included on the HAPs Combutions Emissions Summary sheet.

Methodology:
Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Max. Heat Input (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 hr/yr ÷ 2000 lb/ton

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	49,633	0.95	0.91
Summed Potential Emissions (tons/yr)	49,635		
CO_2e Total (tons/yr)	49,935		

Notes:
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Potential Emissions-GHGs (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

**Appendix A: Emission Calculations
Non-Fuel Grade Ethanol Loading Skids (EU083 and EU084)
Uncontrolled Potential to Emit**

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Emission Factors: AP-42

Non-fuel grade ethanol will be shipped by either truck loading skid EU083 or railcar loading skid EU084.
Both railcars and trucks will be filled by submerged loading process.
Truck loading skid (EU083) and railcar loading skid (EU084) will both be controlled by flare CE019 which has a control efficiency of 98% for VOC and HAPs.

According to AP-42, Chapter 5.2 - Transportation and Marketing of Petroleum Liquids (01/95), the VOC emission factors for the truck and rail loading racks can be estimated from the following equation:

L = 12.46 x (SPM)/T

where:

L = loading loss (lbs/kgal)
S = a saturation factor (see AP-42, Table 5.2-1)
P = true vapor pressure of the liquid loaded (psia)
M = molecular weight of vapors
T = temperature of the bulk liquid loaded (degree R)

Previous Stored Liquid	*S	P (psia)	M (lb/mole lb)	T (degree R)	L (lb/kgal)
Denatured Ethanol (normal)	0.6	0.50	49.7	512.3	0.36
Denatured Ethanol (clean cargo)	0.5	0.50	49.7	512.3	0.30

2. Potential to Emit VOC Uncontrolled/Unlimited (assuming all denatured ethanol loaded out):

Maximum Loading Rate for EU83: 24 kgal/hr (for truck loading)
PTE of VOC Before Control (tons/yr) = 24 kgal/hr * 0.36 lbs/gal * 8760 hr/yr ÷ 2000 lb/ton = 38.12 tons/yr

Maximum Loading Rate for EU84: 40 kgal/hr (for railcar loading)
PTE of VOC Before Control (tons/yr) = 40 kgal/hr * 0.36 lbs/gal * 8760 hr/yr ÷ 2000 lb/ton = 63.53 tons/yr

Worst case scenario is when loading all denatured ethanol to railcars.	**Worst Case Uncontrolled VOC emissions =**	63.53	tons/yr
Worst case scenario when controlled by flare CE019 with an efficiency of 98%.	**Worst Case Controlled VOC emissions =**	1.27	tons/yr

Notes:
Denatured ethanol from normal cargo has a VOC emission factor of 0.36 lbs/kgal, while denatured ethanol from clean cargo has a VOC emission factor of 0.30.
Therefore the emission factor for denatured ethanol (normal) was used as a worst case scenario.

Methodology:
Worse Case Controlled VOC Emissions (tons/yr) = Worse Case Uncontrolled VOC Emissions (tons/yr) ÷ (1 - Control Efficiency)

Appendix A: Emission Calculations
Non-Fuel Grade Ethanol Loading Skids (EU083 and EU084)
Limited VOC Emissions
Potential to Emit HAPs

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

3. VOC Potential Emissions (Uncontrolled):

Annual Non-Fuel Grade Ethanol Production Limit: 60,000 kgal/yr (for both railcar and truck loading)

Different scenarios to determine the worst case scenario:
(1) Assume all denatured ethanol (normal) is loaded to trucks:
VOC (tons/yr) = 0.36 lbs/kgal * 60,000 kgal/yr ÷ 2000 lb/ton = 10.88 tons/yr

(2) Assume all denatured ethanol (normal) is loaded to dedicated railcars:
VOC (tons/yr) = 0.30 lbs/kgal * 60,000 kgal/yr ÷ 2000 lb/ton = 9.07 tons/yr

Worst case scenario is when loading to trucks.	**Worst Case Limited VOC emissions = 10.88 tons/yr**

4. VOC Potential Emissions (Controlled):

Annual Non-Fuel Grade Ethanol Production Limit: 60,000 kgal/yr (for both railcar and truck loading)
Flare Control Efficiency: 98%

Different scenarios to determine the worst case scenario:
(1) Assume all denatured ethanol (normal) is loaded to trucks:
VOC (tons/yr) = 0.36 lbs/kgal * 60,000 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 0.22 tons/yr

(2) Assume all denatured ethanol (normal) is loaded to dedicated railcars:
VOC (tons/yr) = 0.30 lbs/kgal * 60,000 kgal/yr * (1 - 98%) ÷ 2000 lb/ton = 0.18 tons/yr

Worst case scenario is when loading to trucks. Truck and Railcar emissions are controlled by enclosed flare CE019.	**Worst Case Limited VOC emissions = 0.22 tons/yr**

5. Potential to Emit HAPs:

HAP emissions are mainly from the unloading process for trucks and railcars which may have been used to ship gasoline previously.

HAP	HAP Fraction*	Unlimited PTE of HAP Before Control (tons/yr)	Unlimited PTE of HAP After Control (tons/yr)	Limited PTE of HAP After Control (tons/yr)
Benzene	2.50E-03	0.16	3.18E-03	5.44E-04
Carbon Disulfide	2.00E-05	0.001	2.54E-05	4.35E-06
Cumene	1.00E-04	0.01	1.27E-04	2.18E-05
Ethyl benzene	5.00E-05	0.003	6.35E-05	1.09E-05
n-Hexane	5.00E-02	3.18	6.35E-02	1.09E-02
Toluene	5.00E-03	0.32	6.35E-03	1.09E-03
Xylene	5.00E-04	0.03	6.35E-04	1.09E-04
TOTAL HAPs	---	3.70	0.07	0.01

* This is the HAP fraction for gasoline vapors.

Methodology:
Unlimited PTE of HAP Before Control (tons/yr) = Worse Case VOC Emissions (tons/yr) * HAP Fraction
Unlimited PTE of HAP After Control (tons/yr) = Unlimited PTE of HAP Before Control (tons/yr) * (1 - Control Efficiency)
Limited PTE of HAP After Control (tons/yr) = Worse Case Limited VOC Emissions (tons/yr) * HAP Fraction

Appendix A: Emission Calculations
Non-Fuel Grade Ethanol Loading Skids (EU083 and EU084)
Potential to Emit (NO_x, CO)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

6. Potential to Emit (NO_x and CO) from Flare Combustion (CE019)

Maximum Loadout Rate: 40.00 kgal/hr
Limited Loadout Rate: 60,000 kgal/yr

Pollutant	NO_x	CO
Emission Factor (lb/kgal)	0.077	0.129
Unlimited PTE (tons/yr)	13.49	22.60
Limited PTE (tons/yr)	2.31	3.87

Notes:
Particulate (PM, PM_{10}, and $PM_{2.5}$) and SO_2 emission factors are negligible due to the smokeless design and minimal H_2S levels.
Emission factors for NO_x and CO are based on the information provided by the flare manufacturer (MRW Technologies, Inc.)

Methodology:
Unlimited PTE (tons/yr) = Maximum Loadout Rate (kgal/hr) * Emission Factor (lb/kgal) * 8760 hr/yr ÷ 2000 lb/ton
Limited PTE (tons/yr) = Limited Loadout Rate (kgal/yr) * Emission Factor (lb/kgal) ÷ 2000 lb/ton

7. Potential to Emit (GHGs) from Flare Combustion (CE019)

Heat Input Capacity (MMBtu/hr)	HHV (MMBtu/MMCF)	Throughput (MMCF/yr)
10.0	1020	85.88

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor (lb/MMCF)	120,000	2.3	2.2
Potential Emissions (tons/yr)	5,153	0.10	0.09
Summed Potential Emissions (tons/yr)	5,153		
CO_2e Total (tons/yr)	5,184		

Notes:
The N_2O emission factor for uncontrolled is 2.2. The N_2O emission factor for low NO_x burner is 0.64.
Emission factors are from AP 42, Table 1.4-2, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
The Global Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98 Subpart A.

Methodology:
Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) * 8760 hr/yr ÷ HHV (MMBtu/MMCF)
Potential Emissions (tons/yr) = Maximum Heat Input Capacity (MMCF/yr) * Emission Factor (lb/MMCF) ÷ 2000 lb/ton
CO_2e (tons/yr) = [CO_2 Potential Emissions (tons/yr) * CO_2 GWP (1)] + [CH_4 Potential Emissions (tons/yr) * CH_4 GWP (21)] + [N_2O Potential Emissions (tons/yr) * N_2O GWP (310)]

Appendix A: Emission Calculations
Fugitive Emissions From Roads

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Paved Roads

$E = [k * (sL/2)^{0.91} * (W)^{1.02}][1-(P/4N)]$ AP-42, Section 13.2.1.3, Eqn. 2

Factor	Description		PM	PM_{10}	$PM_{2.5}$
k =	PM Particle size multiplier (lb/VMT)	Table 13.2.1-1	0.011	0.002	0.0005
sL =	Road surface silt loading (g/m^2)	Table 13.2.1-3	2.90	2.90	2.90
P =	Number of "wet" days in an averaging period		120	120	120
N =	Number of days in the averaging period		365	365	365
W =	Average vehicle weight (tons)		29	29	29
E =	Emission factor (lb/VMT, vehicle miles traveled)		0.44	0.09	0.02

Emissions from Paved Roads

Activity	No. of Trucks (trucks/yr)	Miles Traveled per Truck (miles/truck)	Annual Mileage (VMT/yr)	Uncontrolled PM Emissions (tpy)	Controlled PM Emissons* (tpy)	Uncontrolled PM_{10} Emissions (tpy)	Controlled PM_{10} Emissions* (tpy)	Uncontrolled $PM_{2.5}$ Emissions (tpy)	Controlled $PM_{2.5}$ Emissions* (tpy)
Grain Receiving	25,872	0.84	21,732	4.77	2.39	0.95	0.48	0.23	0.12
DDGS Loadout	8,400	0.84	7,056	1.55	0.77	0.31	0.15	0.08	0.04
Ethanol Loadout	8,112	0.84	6,814	1.50	0.75	0.30	0.15	0.07	0.04
Denaturant Delivery	375	0.84	315	0.07	0.03	0.01	0.01	0.00	0.002
TOTAL				7.89	3.94	1.58	0.79	0.39	0.19

* Periodic sweeping will be done to provide control (50%) to $PM/PM_{10}/PM_{2.5}$ emissions.

2. Unpaved Roads

$E = k * (s/12)^a * (W/3)^b * [(365-P)/365]$ AP-42, Section 13.2.2.2, Eqns. 1a and 2

Factor	Description	PM	PM_{10}	$PM_{2.5}$
k =	Particle size multiplier (dimensionless)	4.9	1.5	0.15
s =	surface material silt content (%) (Table 13.2.2-1)	8.5	8.5	8.5
W =	mean vehicle weight (tons)	5.0	5.0	5.0
a =	Equation constants (Table 13.2.2-2)	0.7	0.9	0.9
b =	Equation constants (Table 13.2.2-2)	0.45	0.45	0.45
P =	Number of days with at least 0.01 in of precipitation	120	120	120
E =	Emission Factor (lb/VMT)	3.25	0.93	0.09

Total length of unpaved maintenance roads = 0.20 miles

Emission Area	No. of Trucks (trucks/yr)	Miles Traveled per Truck (miles/truck)	Annual Mileage (VMT/yr)	Uncontrolled PM Emissions (tpy)	Controlled PM Emissions (tpy)	Uncontrolled PM_{10} Emissions (tpy)	Controlled PM_{10} Emissions (tpy)	Uncontrolled $PM_{2.5}$ Emissions (tpy)	Controlled $PM_{2.5}$ Emissions (tpy)
Maintenance Roads	730	0.40	292	0.47	0.24	0.14	0.07	0.01	0.01

Methodology:
Annual Mileage (VMT/yr) = No. of Trucks (trucks/yr) * Miles Traveled (miles/truck)
Uncontrolled Emissions (tons/yr) = Annual Mileage (VMT/yr) * Emission Factor (lb/VMT) ÷ 2000 lb/ton

Appendix A: Emission Calculations
Fugitive Emissions From Roads
EPCO Plant

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Paved Roads

$E= [k * (sL/2)^{0.91} * (W)^{1.02}][1-(P/4N)]$ AP-42, Section 13.2.1.3, Eqn. 2

Factor	Description		PM	PM_{10}	$PM_{2.5}$
k =	PM Particle size multiplier (lb/VMT)	Table 13.2.1-1	0.011	0.002	0.0005
sL =	Road surface silt loading (g/m^2)	Table 13.2.1-3	2.90	2.90	2.90
P =	Number of "wet" days in an averaging period		120	120	120
N =	Number of days in the averaging period		365	365	365
W =	Average vehicle weight (tons)		29	29	29
E =	Emission factor (lb/VMT, vehicle miles traveled)		0.44	0.09	0.02

Emissions from Paved Roads

Activity	No. of Trucks (trucks/yr)	Miles Traveled per Truck (miles/truck)	Annual Mileage (VMT/yr)	Uncontrolled PM Emissions (tpy)	Controlled PM Emissons* (tpy)	Uncontrolled PM_{10} Emissions (tpy)	Controlled PM_{10} Emissions* (tpy)	Uncontrolled $PM_{2.5}$ Emissions (tpy)	Controlled $PM_{2.5}$ Emissions* (tpy)
EPCO Trucks**	5,475	0.84	4,599	1.01	0.50	0.20	0.10	0.05	0.02
TOTAL				1.01	0.50	0.20	0.10	0.05	0.02

* Periodic sweeping will be done to provide control (50%) to $PM/PM_{10}/PM_{2.5}$ emissions.

** Based on 15 trucks per day

Methodology:
Annual Mileage (VMT/yr) = No. of Trucks (trucks/yr) * Miles Traveled (miles/truck)
Uncontrolled Emissions (tons/yr) = Annual Mileage (VMT/yr) * Emission Factor (lb/VMT) ÷ 2000 lb/ton

Appendix A: Emission Calculations
Equipment Leaks

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Fugitive VOC Emissions

Process Stream	Equipment Component Source	Product	Component Count	Emission Factor (lb/hr per component)	Uncontrolled Rate		Subpart VV Control	Controlled Rate (lb/hr)	TOC Weight (%)	Emitted Water (lb/hr)	Controlled TOC	
					(lb/hr)	(tons/yr)					(lb/hr)	(tons/yr)
F006	Valves	Gas/Vapor	74	0.01316	0.97	4.27	87.00%	0.13	100.00%	0.00	0.13	0.55
	Valves	Light Liquid	346	0.00889	3.07	13.47	84.00%	0.49	100.00%	0.00	0.49	2.15
	Pump Seals	Light Liquid	21	0.04388	0.92	4.04	69.00%	0.29	100.00%	0.00	0.29	1.25
	Compressors	Gas/Vapor	0	0.50274	0.00	0.00		0.00	100.00%	0.00	0.00	0.00
	Relief Valves	Gas/Vapor	15	0.22932	3.44	15.07	87.00%	0.45	100.00%	0.00	0.45	1.96
	Sampling Connections	All	14	0.03308	0.46	2.03	0.00%	0.46	100.00%	0.00	0.46	2.03
	Open Ended Lines	All	0	0.00375	0.00	0.00		0.00	100.00%	0.00	0.00	0.00
	Flanges	All	297	0.00404	1.20	5.25	0.00%	1.20	100.00%	0.00	1.20	5.25
	TOTAL				10.07	44.11		3.01		0.00	3.01	13.20

Notes:
Component count provided by source.
Emission factors are from Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Table 2-1 and Table 5-2
1 kg = 2.205 pounds

Methodology:
Uncontrolled Rate (lb/hr) = Emission Factor (lb/hr per component) * Component Count
Uncontrolled Rate (tons/yr) = Uncontrolled Rate (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
Controlled Rate (lb/hr) = Uncontrolled Rate (lb/hr) ÷ (1 - Subpart VV Control)
Emitted Water (lb/hr) = Controlled Rate (lb/hr) ÷ (1 - TOC Weight)
Controlled TOC (lb/hr) = Controlled Rate (lb/hr) * TOC Weight
Controlled TOC (tons/yr) = Controlled TOC (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

2. Fugitive HAP Emissions

HAP	HAP Fraction	Uncontrolled Emissions (tons/yr)	Controlled Emissions (tons/yr)
Acetaldehyde	2.00E-04	8.82E-03	2.64E-03
Benzene	2.50E-03	1.10E-01	3.30E-02
Carbon Disulfide	2.00E-05	8.82E-04	2.64E-04
Cumene	1.00E-03	4.41E-02	1.32E-02
Ethylbenzene	5.00E-05	2.21E-03	6.60E-04
n-Hexane	5.00E-02	2.21E+00	6.60E-01
Methanol	2.00E-04	8.82E-03	2.64E-03
Toluene	5.00E-03	2.21E-01	6.60E-02
Xylenes	5.00E-04	2.21E-02	6.60E-03
Total HAPs		2.62	0.78

Methodology:
Uncontrolled HAP Emissions (tons/yr) = Uncontrolled TOC (tons/yr) * HAP Fraction
Controlled HAP Emissions (tons/yr) = Controlled TOC (tons/yr) * HAP Fraction

Appendix A: Emission Calculations
Cooling Tower

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Process Description

Type of Cooling Tower:	Induced Draft	
Circulation Flow Rate:	33,000	gal/min
Total Drift:	0.005%	of the circulating flow
Total Dissolved Solids:	2,500	ppm
Density:	8.345	lbs/gal

Note: The information above was provided by the cooling tower manufacturer for the same units located at a similar source.

2. Potential to Emit

Assume all the dissolved solids become PM_{10} emissions.
Assume all PM and $PM_{2.5}$ emissions equal PM_{10} emissions.

PTE of $PM/PM_{10}/PM_{2.5}$ (lb/hr) = 33,000 gal/min * 60 min/hr * 0.005% * 8.345 lbs/gal * 2,500 ppm * 1/1,000,000 ppm = 2.07 lbs/hr

PTE of $PM/PM_{10}/PM_{2.5}$ (tons/yr) = PTE of $PM/PM_{10}/PM_{2.5}$ (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton = 9.05 tons/yr

Appendix A: Emission Calculations
Cooling Tower
EPCO Plant

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Process Description

Type of Cooling Tower:	Induced Draft	
Circulation Flow Rate:	900	gal/min
Total Drift:	0.005%	of the circulating flow
Total Dissolved Solids:	2,500	ppm
Density:	8.345	lbs/gal

Note: The information above was provided by the cooling tower manufacturer for the same units located at a similar source.

2. Potential to Emit

Assume all the dissolved solids become PM_{10} emissions.

Assume all PM and $PM_{2.5}$ emissions equal PM_{10} emissions.

PTE of PM/PM_{10}/$PM_{2.5}$ (lb/hr) = 33,000 gal/min * 60 min/hr * 0.005% * 8.345 lbs/gal * 2,500 ppm * 1/1,000,000 ppm = 0.06 lbs/hr

PTE of PM/PM_{10}/$PM_{2.5}$ (tons/yr) = PTE of PM/PM_{10}/$PM_{2.5}$ (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton = 0.25 tons/yr

Appendix A: Emission Calculations
Corn Oil Separation Unit and Storage Tank (EU061 and EU062)

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Potential to Emit (PTE) for Corn Oil Separation Unit (EU061):

The thin stillage will be processed through a separation process to collect and store excess corn oil. The separation process will be enclosed resulting in no emissions. Loadout and Truck Traffic emissions are negligible based on low annual throughput.

Potential to Emit (PTE) for Storage Tank (EU062):

These values were provided by the source based on analytical testing.

Pollutant	PTE (lb/hr)	PTE (tons/yr)	HAP?	VOC?
Acetaldehyde	0.0002	8.76E-04	Y	Y
Acetic Acid	0.0390	0.17	N	Y
Acrolein	0.0001	4.38E-04	Y	Y
Ethanol	0.0430	0.19	Y	Y
Ethylacetate**	0.0140	0.06	N	Y
Formaldehyde	0.0002	8.76E-04	Y	Y
Formic Acid	0.0030	0.01	N	Y
2-furaldehyde	0.0001	4.38E-04	N	Y
Lactic Acid	0.0090	0.04	N	Y
Methanol**	0.0140	0.06	Y	Y
Phosphorous**	0.0080	0.04	Y	N
Total VOC	**0.123**	**0.54**		
Total HAP	**0.066**	**0.29**		

** Concentration was reported as less than the detection limit; therefore, the value is half the detection limit.

Appendix A: Emission Calculations
Storage Tanks

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
nificant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Emissions were calculated using Tanks 4.0.9d software and submitted by the source.

Appendix A: Emission Calculations
Proposed Storage Tanks

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

Emissions were calculated using Tanks 4.0.9d software and submitted by the source.
Proposed tanks worst-case HAP emissions is based on highest HAP for each liquid being considered for storge by tan which shall be limited to any single HAP or a combination of these HAPs: benzene, chloroform, dimethyl phthalate, methyl isobutyl ketone, and toluene.
The total worst-case single HAP from the proposed tanks is 1.95 tons per year.
The worst-case single HAP is not acetaldehyde.
The worst-case HAP emission is conservatively assumed to be the same as the potential VOC emissions.
The throughput of the proposed tanks is based on an annual capacity of 60 million gallons of non-fuel grade ethanol.

Appendix A: Emission Calculations
Proposed Equipment Leaks

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Fugitive VOC Emissions

Process Stream	Equipment Component Source	Product	Component Count	Emission Factor (lb/hr per component)	Uncontrolled Rate (lb/hr)	Uncontrolled Rate (tons/yr)	Subpart VV Control	Controlled Rate (lb/hr)	TOC Weight (%)	Emitted Water (lb/hr)	Controlled TOC (lb/hr)	Controlled TOC (tons/yr)
F006	Valves	Gas/Vapor	19	0.01316	0.25	1.10	87.00%	0.03	100.00%	0.00	0.03	0.14
	Valves	Light Liquid	87	0.00889	0.77	3.39	84.00%	0.12	100.00%	0.00	0.12	0.54
	Pump Seals	Light Liquid	5	0.04388	0.22	0.96	69.00%	0.07	100.00%	0.00	0.07	0.30
	Compressors	Gas/Vapor	0	0.50274	0.00	0.00		0.00	100.00%	0.00	0.00	0.00
	Relief Valves	Gas/Vapor	4	0.22932	0.92	4.02	87.00%	0.12	100.00%	0.00	0.12	0.52
	Sampling Connections	All	4	0.03308	0.13	0.58	0.00%	0.13	100.00%	0.00	0.13	0.58
	Open Ended Lines	All	0	0.00375	0.00	0.00		0.00	100.00%	0.00	0.00	0.00
	Flanges	All	74	0.00404	0.30	1.31	0.00%	0.30	100.00%	0.00	0.30	1.31
	TOTAL				2.59	11.35		0.77		0.00	0.77	3.39

Notes:
Component count provided by source.
Emission factors are from Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017. Table 2-1 and Table 5-2
1 kg = 2.205 pounds

Methodology:
Uncontrolled Rate (lb/hr) = Emission Factor (lb/hr per component) * Component Count
Uncontrolled Rate (tons/yr) = Uncontrolled Rate (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton
Controlled Rate (lb/hr) = Uncontrolled Rate (lb/hr) ÷ (1 - Subpart VV Control)
Emitted Water (lb/hr) = Controlled Rate (lb/hr) ÷ (1 - TOC Weight)
Controlled TOC (lb/hr) = Controlled Rate (lb/hr) * TOC Weight
Controlled TOC (tons/yr) = Controlled TOC (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton

2. Fugitive HAP Emissions

HAP	HAP Fraction	Uncontrolled Emissions (tons/yr)	Controlled Emissions (tons/yr)
Acetaldehyde	2.00E-04	2.27E-03	6.78E-04
Benzene	2.50E-03	2.84E-02	8.48E-03
Carbon Disulfide	2.00E-05	2.27E-04	6.78E-05
Cumene	1.00E-03	1.13E-02	3.39E-03
Ethylbenzene	5.00E-05	5.67E-04	1.70E-04
n-Hexane	5.00E-02	5.67E-01	1.70E-01
Methanol	2.00E-04	2.27E-03	6.78E-04
Toluene	5.00E-03	5.67E-02	1.70E-02
Xylenes	5.00E-04	5.67E-03	1.70E-03
Total HAPs		0.67	0.20

Methodology:
Fugitive HAP Emissions (tons/yr) = Controlled TOC (tons/yr) * HAP Fraction

Appendix A: Emission Calculations
Proposed Cooling Tower

Company Name: Central Indiana Ethanol, LLC
Address: 2955 West Delphi Pike, Marion, IN 46952
Significant Permit Modification No.: 053-32519-00062
Reviewer: John Haney/Julie Alexander
Date: February 25, 2013

1. Process Description

Type of Cooling Tower:	Induced Draft	
Circulation Flow Rate:	21,000	gal/min
Total Drift:	0.005%	of the circulating flow
Total Dissolved Solids:	2,500	ppm
Density:	8.345	lbs/gal

Note: The information above was provided by the cooling tower manufacturer for the same units located at a similar source.

2. Potential to Emit

Assume all the dissolved solids become PM_{10} emissions.
Assume all PM and $PM_{2.5}$ emissions equal PM_{10} emissions.

PTE of $PM/PM_{10}/PM_{2.5}$ (lb/hr) = 33,000 gal/min * 60 min/hr * 0.005% * 8.345 lbs/gal * 2,500 ppm * 1/1,000,000 ppm = 1.31 lbs/hr
PTE of $PM/PM_{10}/PM_{2.5}$ (tons/yr) = PTE of $PM/PM_{10}/PM_{2.5}$ (lb/hr) * 8760 hr/yr ÷ 2000 lb/ton = 5.76 tons/yr

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Norm Currey
Central Indiana Ethanol, LLC
2955 West Delphi Pike
Marion, IN 46952

DATE: July 31, 2013

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

SUBJECT: Final Decision
Significant Source Modification to a Part 70 Operating Permit
053-32519-00062

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:
Ryan Drook, President/CEO
Ann Curnow, Natural Resources Group LLC
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 6/13/2013

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

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

July 31, 2013

TO: Marion Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Central Indiana Ethanol, LLC
Permit Number: 053-32519-00062

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 7/31/2013 Central Indiana Ethanol, LLC 053-32519-00062 FINAL			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	►	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Norm Currey Central Indiana Ethanol, LLC 2955 W Delphi Pike Marion IN 46952 (Source CAATS) Confirmed Delivery									
2		Ryan Drook President/CEO Central Indiana Ethanol, LLC 2955 W Delphi Pike Marion IN 46952 *(RO CAATS)*									
3		Marion City Council and Mayors Office 301 S. Branson Street Marion IN 46952-4052 *(Local Official)*									
4		Grant County Commissioners 401 South Adams Marion IN 46953 *(Local Official)*									
5		Ms. Mary Shipley 10968 E 100 S Marion IN 46953 *(Affected Party)*									
6		Grant County Health Department 401 S. Adams St, Courthouse Complex Marion IN 46953-2031 *(Health Department)*									
7		Mr. Thomas Lee Clevenger 4005 South Franks Lane Selma IN 47383 *(Affected Party)*									
8		Marion Public Library 600 S Washington St Marion IN 46953 *(Library)*									
9		Mr. Colin OBrien Natural Resources Defense Council 1152 15th St NW, Suite 300 Washington DC 20005 *(Affected Party)*									
10		Ginny King Marathon Petroleum Company 539 S Main St Findley OH 45870 *(Attorney)*									
11		Ann Curnow Natural Resource Group LLC 80 S 8th Street 1000 IDS Center Minneapolis MN 55402 *(Consultant)*									
12											
13											
14											
15											

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	
10			The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877