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
Date:	February 11, 2015
From:	Matthew Stuckey, Chief Permits Branch Office of Air Quality
Source Name:	Johnson Melloh Solutions - IMC Central Energy Plant
Permit Level:	Title V - Renewal Administrative Permit
Permit Number:	097 - 34078 - 00586
Source Location:	2745 South Hoffman Road, Suite 504, Indianapolis, Indiana
Type of Action Taken:	Permit Renewal Revisions to permit requirements

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: http://www.in.gov/apps/idem/caats/
To view the document, select Search option 3, then enter permit 34078.

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

Indiana Government Center North, Room 1201
100 North Senate Avenue, MC 50-07
Indianapolis, IN 46204
Phone: 1-800-451-6027 (ext. 4-0965)
Fax (317) 232-8659

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

(continues on next page)

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

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

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

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

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

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

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

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Administrative Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Johnson Melloh Solutions - IMC Central Energy Plant
2745 South Hoffman Road, Suite 504
Indianapolis, Indiana 46241

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

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Operation Permit No. T097-34078-00586	
Issued by: Nathan C. Bell, Section Chief Permits Branch Office of Air Quality	Issuance Date: February 11, 2015 Expiration Date: February 11, 2020

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1, 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 central energy plant.

Source Address:	2745 South Hoffman Road, Suite 504, Indianapolis, IN 46241
General Source Phone Number:	(317) 227-5066
SIC Code:	4961 (Steam and Air Conditioning Supply)
County Location:	Marion County, Decatur and Wayne Townships
Source Location Status:	Nonattainment for SO_2 Attainment for all other criteria pollutants
Source Status:	Part 70 Operating Permit Program Minor Source, under PSD and Emission Offset Rules Minor Source, Section 112 of the Clean Air Act Nested Source with fossil fuel fired boilers (or combinations thereof) totaling more than two hundred fifty million (250,000,000) British thermal units per hour heat input, as 1 of 28 Source Categories

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

This collocated airfield, aerospace vehicle maintenance center and central energy plant source consists of five (5) plants:

(a) Plant 1, Indianapolis Airport Authority (097-00156), is located at 2825 West Perimeter Road, Indianapolis, Indiana 46241 and 7800 Col. H. Weir Cook Memorial Drive (and various collocated addresses), Indianapolis, Indiana 46241;

(b) Plant 2, Johnson Melloh Solutions - IMC Central Energy Plant (097-00586), is located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241;

(c) Plant 3, AAR Aircraft Services, Indianapolis (097-00559), is located at 2825 West Perimeter Road, Indianapolis, Indiana 46241;

(d) Plant 5, Chautauqua Airlines (097-00668), is located at 2745 South Hoffman Road, Dock 67, Hangar 7A-7B, Indianapolis, IN 46241; and

(e) Plant 6, ASIG Aircraft Services International Group (097-00667), is located at 2050 Hoffman Road, Indianapolis, IN 46241.

IDEM, OAQ has determined that since the five (5) plants are located on contiguous or adjacent properties and are under common control of the same entity, the Indianapolis Airport Authority (IAA), they will be considered one (1) source.

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, identified as Plant 2, located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241 consists of the following emission units and pollution control devices:

(a) Natural gas-fired Boiler #1, manufactured by Cleaver Brooks, identified as emission unit 001, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 12.6 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 001, installed in 1993.
[40 CFR 60, Subpart Dc]

(b) Natural gas-fired Boiler #2, manufactured by Cleaver Brooks, identified as emission unit 002, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 25.2 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 002, installed in 1993.
[40 CFR 60, Subpart Dc]

(c) Natural gas-fired Boiler #3, manufactured by Nebraska, identified as emission unit 003, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 003, installed in 1994.
[40 CFR 60, Subpart Db]

(d) Natural gas-fired Boiler #4, manufactured by Nebraska, identified as emission unit 004, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 004, installed in 1994.
[40 CFR 60, Subpart Db]

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

This stationary source, identified as Plant 2, located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241 includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Degreasing operations that do not individually exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(b) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors, electrostatic precipitators, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations with uncontrolled potential to emit of less than five (5) pounds of PM-10 per hour and less than twenty five (25) pounds of PM-10 per day. [326 IAC 6.5-1-2(a)]

(c) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4]
[326 IAC 6.5-1-2(a)]

(d) Emergency Generator #1, manufactured by Cummins, model number KTA39-G4, identified as emission unit 005, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 005, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(e) Emergency Generator #2, manufactured by Cummins, model number KTA39-G4, identified as emission unit 006, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 006, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(f) Emergency Generator #3, manufactured by Cummins, model, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 007, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(g) Fire Pump Engine #1, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 008, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 008, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(h) Fire Pump Engine #2, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 009, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 009, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(i) Fire Pump Engine #3, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 010, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 010, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(j) Fire Pump Engine #4, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 011, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 011, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(k) Fire Pump Engine # 5, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 012, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 012, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

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 Definitions [326 IAC 2-7-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

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

(a) This permit, T097-34078-00586, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

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

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

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

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

B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

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

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

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

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

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

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

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

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

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

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

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

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

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

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

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

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than April 15 of each year to:

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

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

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

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

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

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

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

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

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

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

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T097-34078-00586 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit.

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

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

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

(1) That this permit contains a material mistake.

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

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

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

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

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

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

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

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

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

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

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12]

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

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

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

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

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

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

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

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

(4) The Permittee notifies the:

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

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

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

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

B.20 Source Modification Requirement [326 IAC 2-7-10.5]

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

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]

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

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

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

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

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

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

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

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

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

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

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

C.2 Open Burning [326 IAC 4-1] [IC 13-17-9]

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

C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

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

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

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

C.5 Stack Height [326 IAC 1-7]

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

C.6 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

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

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

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

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

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

C.7 Performance Testing [326 IAC 3-6]

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

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

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

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

Compliance Requirements [326 IAC 2-1.1-11]

C.8 Compliance Requirements [326 IAC 2-1.1-11]

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

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

C.9 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

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

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

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

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

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.10 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

C.11 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.12 Risk Management Plan [326 IAC 2-7-5(12)] [40 CFR 68]

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

C.13 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

C.14 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

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

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

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

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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

C.15 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(b)(2), starting in 2005 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

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

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.16 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

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

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

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

C.17 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

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

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

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.18 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Natural gas-fired Boiler #1, manufactured by Cleaver Brooks, identified as emission unit 001, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 12.6 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 001, installed in 1993. [40 CFR 60, Subpart Dc]

(b) Natural gas-fired Boiler #2, manufactured by Cleaver Brooks, identified as emission unit 002, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 25.2 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 002, installed in 1993.[40 CFR 60, Subpart Dc]

(c) Natural gas-fired Boiler #3, manufactured by Nebraska, identified as emission unit 003, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 003, installed in 1994. [40 CFR 60, Subpart Db]

(d) Natural gas-fired Boiler #4, manufactured by Nebraska, identified as emission unit 004, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 004, installed in 1994. [40 CFR 60, Subpart Db]

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

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

D.1.1 Nested Boiler Limit [326 IAC 2-1.1-5]

(a) The Permittee shall limit the combustion of Jet A fuel, No. 2 fuel oil and/or Jet A off spec fuel in Boiler #1, Boiler #2, Boiler #3 and Boiler #4 to a combined total of less than 4,309,356 gallons per twelve (12) consecutive month period with compliance determined at the end of each month; and

(b) The sulfur content of Jet A fuel, No. 2 fuel oil and/or Jet A fuel off spec fuel shall not exceed 0.28 weight percent.

Compliance with these limits, combined with the potential to emit SO_2 from insignificant activities at IMCCEP, and potential emissions of AAR emission units, shall limit the source-wide PTE of SO_2 to less than one hundred (100) tons per twelve (12) consecutive month period and shall render the requirements of 326 IAC 2-1.1-5 (Non Attainment New Source Review) not applicable to all the nested boilers and shall render the requirements of 326 IAC 2-1.1-5 (Non-Attainment New Source Review) not applicable to the entire source.

D.1.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1-2]

Pursuant to 326 IAC 7-1.1-2 (SO_2 Emission Limitations), SO_2 emissions from Boiler #2, Boiler #3 and Boiler #4 shall not exceed five tenths (0.5) pounds per MMBtu heat input when combusting No. 2 fuel oil and/or Jet A fuel oil. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.1.3 PSD Minor Limit [326 IAC 2-2]

(a) NO_X emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP, Plant 2, shall be limited to less than a combined total of 83.2 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(1) NO_X emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP shall be determined as follows:

$E_{NOX} = (F_{ng} \times EF_{ng})/2000 + (F_{Jet\ A/No.2} \times EF_{Jet\ A/No.2})/2000$ + CEM data (in tons per month)

Where: E_{NOX} = NO_X emissions in tons per month
F_{ng} = Monthly natural gas usage in Boiler #1 and Boiler #2 in million cubic feet
EF_{ng}= 32 pounds NO_X emissions per million cubic feet natural gas burned in Boiler #1 and Boiler #2
$F_{Jet\ A/No.2}$ = Monthly Jet A/ No. 2 fuel oil usage in Boiler #1 and Boiler #2
$EF_{Jet\ A/No.2}$ = 20 pounds NO_X emissions per thousand gallons of Jet A/No. 2 fuel oil burned in Boiler #1 and Boiler #2
CEM data= NO_X continuous emission monitoring data converted to tons per month for Boiler #3 and Boiler #4

(b) CO emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP, Plant 2, shall be limited to less than a combined total of 85.90 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(1) CO emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP shall be determined as follows:

$E_{CO} = (F_{ng} \times EF_{ng})/2000 + (F_{Jet\ A/No.2} \times EF_{Jet\ A/No.2})/2000$

Where: E_{CO} = CO emissions in tons per month
F_{ng} = Monthly natural gas usage in Boiler #1, Boiler #2, Boiler #3, and Boiler #4 in million cubic feet
EF_{ng} = 84 pounds CO emissions per million cubic feet natural gas burned in Boiler #1, Boiler #2, Boiler #3, and Boiler #4
$F_{Jet\ A/No.2}$ = Monthly Jet A/ No. 2 fuel oil usage in Boiler #1, Boiler #2, Boiler #3, and Boiler #4
$EF_{Jet\ A/No.2}$ = 5 pounds CO emissions per thousand gallons of Jet A/No. 2 fuel oil burned in Boiler #1, Boiler #2, Boiler #3, and Boiler #4

Compliance with these limits shall limit the potential to emit of CO and NO_x from all four boilers to less than one hundred (100) tons of per twelve (12) consecutive month period, each, and shall render the requirements of 326 IAC 2-2 (PSD) not applicable to the nested source.

D.1.4 PM Limitations Except Lake County [326 IAC 6.5]

(a) Pursuant to 326 IAC 6.5-1-2(b)(2), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #1, Boiler #2, Boiler #3, and Boiler #4 shall not exceed 0.15 lb/MMBtu, each while combusting No. 2 fuel oil and/or Jet A fuel oil.

(b) Pursuant to 326 IAC 6.5-1-2(b)(3), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #1, Boiler #2, Boiler #3, and Boiler #4 shall not exceed 0.01 grain per dry standard cubic foot while combusting natural gas.

D.1.5 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and their control equipment. 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.1.6 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 7-2-1]

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

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

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

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

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

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

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

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

D.1.7 Continuous Emission Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1),(6)] [40 CFR 60 Subpart Db]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), the Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_x emissions on stack 003 and stack 004 for Boiler #3 and Boiler #4 that meet all applicable performance specifications of 326 IAC 3-5-2.

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

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, 40 CFR 75 and 40 CFR 96.

Compliance Monitoring Requirements

D.1.8 Visible Emissions Notations

(a) Visible emission notations of the stack exhausts of Boiler #1 (stack 001), Boiler #2 (stack 002), Boiler #3 (stack 003), and Boiler #4 (stack 004), shall be performed once per day during normal daylight hours when burning No. 2 fuel oil and/or Jet A fuel oil. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, “normal” means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

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

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

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

D.1.9 Continuous Emissions Monitoring (CEMS) Equipment Downtime

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

(b) Whenever a NO_x CEMS is down for more than twenty-four (24) hours, the Permittee shall:

(1) follow best combustion practices; and

(2) shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

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

D.1.10 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.2 and D.1.6, the Permittee shall maintain records in accordance with (1) through (7) below. Records maintained for (1) through (7) shall be taken monthly and shall be complete and sufficient to establish compliance with the SO_2 emission limit established in Condition D.1.2.

(1) Calendar dates covered in the compliance determination period;

(2) Actual Jet A, off spec Jet A fuel and No. 2 fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) To certify compliance when burning natural gas only, the Permittee shall maintain records of natural gas burned.

If fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier;

(6) A statement from the fuel supplier that certifies the sulfur content of the Jet A fuel, off spec Jet A fuel and No. 2 fuel oil; and

(7) A certified statement signed by the Permittee that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(b) The Permittee shall record and maintain records of the amount of each fuel combusted during each calendar month in Boiler #1, Boiler #2, Boiler #3 and Boiler #4.

(c) To document the compliance status with D.1.3(a), the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(d) To document the compliance status with D.1.3(a) and (b), the Permittee shall maintain monthly records of NO_x and CO emissions from Boiler #1, Boiler #2, Boiler #3, and Boiler #4.

(e) To document compliance with Condition D.1.8, the Permittee shall maintain daily records of visible emission notations of the boiler stack exhausts. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).

(f) In order to document the compliance status with Condition D.1.9(a), in the event that a breakdown of the NO_x CEMS occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(g) In order to document the compliance status with Condition D.1.9(b), whenever a NO_x CEMS is malfunctioning or is down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall maintain the following records:

(1) best combustion practices followed; and

(2) the average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(h) Section C - General Record Keeping Requirements contains the Permittee' obligations with regard to the records required by this condition.

D.1.11 Reporting Requirements

Quarterly summaries of the information to document the compliance status with Conditions D.1.1, D.1.3(a) and D.1.3(b) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The reports submitted by the Permittee do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

D.1.12 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(A)(iii)] [326 IAC 3-5]

(a) The Permittee shall prepare and submit to IDEM, OAQ a written report of the results of the calibration gas audits and relative accuracy test audits for each calendar quarter within thirty (30) calendar days after the end of each quarter. The report must contain the information required by 326 IAC 3-5-5(e)(2).

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

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

(1) date of downtime;

(2) time of commencement;

(3) duration of each downtime;

(4) reasons for each downtime; and

(5) nature of system repairs and adjustments.

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

(c) Section C - General Reporting contains the Permittee’s obligation with regard to the reporting required by this condition.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Insignificant Activities:

(a) Degreasing operations that do not individually exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(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 Volatile Organic Compounds (VOCs) [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), for cold cleaning operations constructed after January 1, 1980, the owner or operator shall:

(a) Equip the degreaser with a cover;

(b) Equip the degreaser with a device for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the degreaser;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements; and

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

D.2.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8, on and after January 1, 2015, material requirements for cold cleaner degreasers are as follows:

(a) The Permittee shall not cause or allow the sale of solvents for use in cold cleaner degreasing operations with a VOC composite partial vapor pressure, when diluted at the manufacturer's recommended blend and dilution, that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit) in an amount greater than five (5) gallons during any seven (7) consecutive days to an individual or business.

(b) The Permittee shall not operate the cold cleaner degreasers with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(c) The Permittee shall maintain the following records for each purchase:

(1) The name and address of the solvent supplier

(2) The date of purchase (or invoice/bill date of contract servicer indicating service date;

(3) The type of solvent purchased;

(4) The total volume of solvent purchased;

(5) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Insignificant Activities:

(b) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors, electrostatic precipitators, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations with uncontrolled potential to emit of less than five (5) pounds of PM-10 per hour and less than twenty five (25) pounds of PM-10 per day. [326 IAC 6.5-1-2(a)]

(c) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4] [326 IAC 6.5-1-2(a)]

(d) Emergency Generator #1, manufactured by Cummins, model number KTA39-G4, identified as emission unit 005, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 005, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(e) Emergency Generator #2, manufactured by Cummins, model number KTA39-G4, identified as emission unit 006, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 006, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(f) Emergency Generator #3, manufactured by Cummins, model, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 007, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(g) Fire Pump Engine #1, manufactured by Detroit Diesel, model number DDFP-L8FA- 8189F, identified as emission unit 008, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 008, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(h) Fire Pump Engine #2, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 009, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 009, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(i) Fire Pump Engine #3, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 010, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 010, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(j) Fire Pump Engine #4, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 011, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 011, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(k) Fire Pump Engine # 5, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 012, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 012, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(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.3.1 PM Limitations Except Lake County [326 IAC 6.5]

Pursuant to 326 IAC 6.5-1-2(a), particulate matter (PM) emissions from the following processes shall not exceed 0.03 grains per dry standard cubic foot:

(1) Grinding and machining operations;
(2) Paved and unpaved roads and parking lots with public access;
(2) Emergency Generator #1;
(3) Emergency Generator #2;
(4) Emergency Generator #3;
(5) Fire Pump Engine #1;
(6) Fire Pump Engine #2;
(7) Fire Pump Engine #3;
(8) Fire Pump Engine #4; and
(9) Fire Pump Engine #5.

D.3.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the grinding and machining operations, the emergency generators, the fire pump engines, and any associated 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.3.3 Particulate Control

In order to demonstrate the compliance status with Condition D.3.1, the control device(s) for the grinding and machining operations shall be in operation and controlling emissions from the grinding and machining operations at all times the grinding and machining device(s) is(are) in operation.

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Natural gas-fired Boiler #1, manufactured by Cleaver Brooks, identified as emission unit 001, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 12.6 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 001, installed in 1993. [40 CFR 60, Subpart Dc]

(b) Natural gas-fired Boiler #2, manufactured by Cleaver Brooks, identified as emission unit 002, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 25.2 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 002, installed in 1993.[40 CFR 60, Subpart Dc]

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

New Source Performance Standards (NSPS) [326 IAC 12]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference 326 IAC 12-1, for Boiler #1 and Boiler #2, except as otherwise specified in 40 CFR 60, Subpart Dc.

E.1.2 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Dc][326 IAC 12]

Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall comply with the following provisions of the Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (included as Attachment A to this permit), which are incorporated as 326 IAC 12, for Boiler #1 and Boiler #2:

(1) 40 CFR 60.40c(a) and (b);
(2) 40 CFR 60.41c;
(3) 40 CFR 60.42c(d), (g), (h)(1), and (i);
(4) 40 CFR 60.44c(a), and (h);
(5) 40 CFR 60.46c(e); and
(6) 40 CFR 60.48c(a)(1), (b), (d), (e)(1), (e)(11), (f)(1), (g)(3), (i), and (j).

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) Natural gas-fired Boiler #3, manufactured by Nebraska, identified as emission unit 003, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 003, installed in 1994. [40 CFR 60, Subpart Db]

(d) Natural gas-fired Boiler #4, manufactured by Nebraska, identified as emission unit 004, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 004, installed in 1994. [40 CFR 60, Subpart Db]

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

New Source Performance Standards (NSPS) [326 IAC 12]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference 326 IAC 12-1 for Boiler #3 and Boiler #4, except as otherwise specified in 40 CFR 60, Subpart Db.

E.2.2 New Source Performance Standards (NSPS) [40 CFR 60, Subpart Db][326 IAC 12]

Pursuant to 40 CFR 60, Subpart Db, the Permittee shall comply with the following provisions of the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (included as Attachment B to this permit), which are incorporated as 326 IAC 12, for Boiler #3 and Boiler #4:

(1) 40 CFR 60.40b(a), (g), and (j);
(2) 40 CFR 60.41b;
(3) 40 CFR 60.42b(a), (e), (g), and (j);
(4) 40 CFR 60.43b(f), and (g);
(5) 40 CFR 60.44b(a), (h), and (i);
(6) 40 CFR 60.45b(j) and (k);
(7) 40 CFR 60.46b(a), (c), (d)(7), (e)(1), and (e)(4);
(8) 40 CFR 60.47b(f);
(9) 40 CFR 60.48b(b)(1), (c), (d), (e)(2), (f), (j)(2) and (l); and
(10) 40 CFR 60.49b(a), (b), (d)(1), (f)(1), (g), (h)(1), (h)(2)(i), (h)(3), (i), (j), (o), (r)(1), (v), and (w).

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Insignificant Activities:

(d) Emergency Generator #1, manufactured by Cummins, model number KTA39-G4, identified as emission unit 005, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 005, installed in 1993.
[40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(e) Emergency Generator #2, manufactured by Cummins, model number KTA39-G4, identified as emission unit 006, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 006, installed in 1993.
[40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(f) Emergency Generator #3, manufactured by Cummins, model, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 007, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(g) Fire Pump Engine #1, manufactured by Detroit Diesel, model number DDFP-L8FA- 8189F, identified as emission unit 008, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 008, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(h) Fire Pump Engine #2, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 009, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 009, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(i) Fire Pump Engine #3, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 010, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 010, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(j) Fire Pump Engine #4, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 011, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 011, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(k) Fire Pump Engine # 5, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 012, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 012, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

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

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements

E.3.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart A]

(a) Pursuant to 40 CFR 63.6665, the Permittee shall comply with the provisions of 40 CFR 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the reciprocating internal combustion engines, identified as Emergency Generators #1 through #3 and Fire Pump Engines #1 through #5, as specified in 40 CFR 63, Subpart ZZZZ in accordance with the schedule in 40 CFR 63, Subpart ZZZZ.

(b) Pursuant to 40 CFR 63.10, 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 Avenue
MC 61-53 IGCN
Indianapolis, Indiana 46204-2251

E.3.2 National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR 63, Subpart ZZZZ] [326 IAC 20-82]

Pursuant to 40 CFR 63, Subpart ZZZZ, the Permittee shall comply with the following provisions of 40 CFR 63, Subpart ZZZZ (included as Attachment C to this permit) which are incorporated by reference as 326 IAC 20-82, for the reciprocating internal combustion engines, identified as Emergency Generators #1 through #3 and Fire Pump Engines #1 through #5:

(1) 40 CFR 63.6580;
(2) 40 CFR 63.6585(a), and (c);
(3) 40 CFR 63.6590(a)(1)(iii);
(4) 40 CFR 63.6595(a), and (c);
(5) 40 CFR 63.6603(a);
(6) 40 CFR 63.6605;
(7) 40 CFR 63.6612(a);
(8) 40 CFR 63.6620(a);
(9) 40 CFR 63.6625(e)(3), (f), (h), and (i);
(10) 40 CFR 63.6640(a), (b), (e), (f)(1), (f)(2)(i), and (f)(4);
(11) 40 CFR 63.6645(a)(5);
(12) 40 CFR 63.6650(f);
(13) 40 CFR 63.6655(e)(2), and (f)(2);
(14) 40 CFR 63.6660;
(15) 40 CFR 63.6665;
(16) 40 CFR 63.6670;
(17) 40 CFR 63.6675;
(18) Table 2d (Item 4); and
(19) Table 8.

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

Source Name: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586

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: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586

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 – Fuel Oil Usage

Source Name: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586
Facility: Boiler #1, Boiler #2, Boiler #3, and Boiler #4
Parameter: Combined Jet A fuel, No. 2 fuel oil/off spec Jet A fuel usage.
Limit: Less than 4,309,356 gallons per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report – NO_x Emissions

Source Name: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586
Facility: Boiler #1, Boiler #2, Boiler #3, and Boiler #4
Parameter: Combined NOx emissions in tons
Limit: Less than 83.2 tons NOx per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report – CO Emissions

Source Name: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586
Facility: Boiler #1, Boiler #2, Boiler #3, and Boiler #4
Parameter: Combined CO emissions in tons.
Limit: Less than 85.90 tons CO per twelve (12) consecutive month period, with compliance determined at the end of each month.

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total

☐ 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: Johnson Melloh Solutions - IMC Central Energy Plant
Source Address: 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241
Part 70 Permit No.: T097-34078-00586

Months: _____ to _____ Year: _____

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: _____

Attachment A

Part 70 Administrative Operating Permit No: T097-34078-00586

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

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 (SO2).

(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:

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

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:

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

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:

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

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]

Attachment B

Part 70 Administrative Operating Permit No: T097-34078-00586

[Downloaded from the eCFR on May 21, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the NO_X standards under this subpart and the PM and SO_2 standards under subpart D (§ 60.42 and § 60.43).

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

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_X and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

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

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, § 60.40).

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

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.41b Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration , also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

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

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

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

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

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

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

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

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

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

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

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

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

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

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

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

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

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

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

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

Where:

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

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

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

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

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction,

or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

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

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

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

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from

combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

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

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in § 60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

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

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

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

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

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§ 60.44b Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_X emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_X emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_X emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_X emission limit will be established at the NO_X emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_X emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_X emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_X emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_X emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_X emission limits of this section. The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

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

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

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

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

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

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

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

(a) The SO_2 emission standards in § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of § 60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

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

Where:

%P_s = Potential SO_2 emission rate, 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.

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

(i) An adjusted hourly SO_2 emission rate ($E_{ho}{}^{o}$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (Eao o). The Eho° is computed using the following formula:

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

Where:

$E_{ho}{}^{o}$ = Adjusted hourly SO_2 emission rate, 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 the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

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

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g{}^o$) is computed from the adjusted Eao o from paragraph (b)(3)(i) of this section and an adjusted average SO2 inlet rate (Eai o) using the following formula:

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

To compute Eai o , an adjusted hourly SO2 inlet rate (Ehi o) is used. The Ehi o is computed using the following formula:

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

Where:

Ehi o = Adjusted hourly SO2 inlet rate, ng/J (lb/MMBtu); and

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

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

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

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§ 60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in § 60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

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

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

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

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

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

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring NO_X under § 60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under § 60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring NO_X and O_2 and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under § 60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs § 60.43b(a)(4) or § 60.43b(h)(5) shall follow the applicable procedures in § 60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

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

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

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

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

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

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

(14) 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.

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

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

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

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D , shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

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

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2 , CO_2 , and O_2 monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

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

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

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

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_X standards in § 60.44b(a)(4), § 60.44b(e), or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

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

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

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

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

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

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

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

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

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

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

(4) Notification that an emerging technology will be used for controlling emissions of SO_2 . The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 , PM, and/or NO_X emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_X standard in § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in § 60.48b(g)(2) and the records to be maintained in § 60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in § 60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in § 60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in § 60.43b(f) or to the operating parameter monitoring requirements in § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

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

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in § 60.42(b) for which the minimum amount of data required in § 60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this

definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions* .

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”) and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for* NO_X . (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for* NO_X . (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

Attachment C

Part 70 Administrative Operating Permit No: T097-34078-00586

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq. 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 —15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

%CO_2 = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR

part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the

engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

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

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP

emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2 .

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2 .

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X , CO, and volatile organic compounds (VOC) into CO_2 , nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3 H_8$.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

Table 1 a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE > 500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1 b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent $O_2$and not using NSCR.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

Table 2 a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2 b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

Table 2 c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

Table 2 d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Measure the O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a c]	(a) Measurements to determine O_2must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005) [a b c]or Method 10 of 40 CFR part 60, appendix A	(a) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i)	(a) if using a control device, the sampling site must be located at the outlet of the control device.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522-00 (Reapproved 2005).[a]	(a) measurements to determine O_2concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[a]provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00 (2005),[a] [c]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03.

[c] ASTM-D6522-00 (2005) may be used to test both CI and SI stationary RICE.

[78 FR 6711, Jan. 30, 2013]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2,or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5).

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. annually according to the requirements in § 63.6650(h)(2)-(3).

[78 FR 6719, Jan. 30, 2013]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes.	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes.	
§ 63.4	Prohibited activities and circumvention	Yes.	
§ 63.5	Construction and reconstruction	Yes.	
§ 63.6(a)	Applicability	Yes.	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§ 63.6(b)(5)	Notification	Yes.	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No.	
§ 63.6(f)(1)	Applicability of standards	No.	
§ 63.6(f)(2)	Methods for determining compliance	Yes.	
§ 63.6(f)(3)	Finding of compliance	Yes.	
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(j)	Presidential compliance exemption	Yes.	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes.	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes.	
§ 63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes.	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§ 63.7(f)	Alternative test method provisions	Yes.	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§ 63.7(h)	Waiver of tests	Yes.	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes.	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No.	
§ 63.8(b)(1)	Monitoring	Yes.	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.8(d)	CMS quality control	Yes.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
		Except that § 63.8(e) only applies as specified in § 63.6645.	
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
		Except that § 63.9(b) only applies as specified in § 63.6645.	
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that § 63.9(g) only applies as specified in § 63.6645.	
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes.	
§ 63.9(j)	Change in previous information	Yes.	
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes.	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes.	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§ 63.10(b)(3)	Records of applicability determination	Yes.	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes.	
§ 63.10(d)(2)	Report of performance test results	Yes.	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes.	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that § 63.10(e)(3)(i) (C) is reserved.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§ 63.11	Flares	No.	
§ 63.12	State authority and delegations	Yes.	
§ 63.13	Addresses	Yes.	
§ 63.14	Incorporation by reference	Yes.	
§ 63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2 , or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ

and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2 ; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2 . When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an

EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2 , whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____											
Run Type:	(_)				(_)			(_)			(_)
(X)	Pre-Sample Calibration				Stack Gas Sample			Post-Sample Cal. Check			Repeatability Check
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate

Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											
″											
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″											
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″											
Mean											
Refresh Phase											
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″											
″											

[78 FR 6721, Jan. 30, 2013]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a
Part 70 Administrative Operating Permit Renewal

Source Background and Description

Source Name:	Johnson Melloh Solution – IMC Central Energy Plant
Source Location:	2745 South Hoffman Road, Suite 504, Indianapolis, IN 46241
County:	Marion County, Decatur and Wayne Townships
SIC Code:	4561 (Steam and Air Conditioning Supply)
County Location:	Marion County, Decatur and Wayne Townships
Permit Renewal No.:	T097-34078-00586
Permit Reviewer:	David Matousek

The Office of Air Quality (OAQ) has reviewed the operating permit renewal application from Johnson Melloh Solution – IMC Central Energy Plant relating to the operation of a stationary central energy plant. On January 14, 2014, Johnson Melloh Solution – IMC Central Energy Plant submitted an application to the OAQ requesting to renew its operating permit. Johnson Melloh Solution – IMC Central Energy Plant was issued its first Part 70 Administrative Operating Permit Renewal T097-25314-00586 on October 15, 2009.

Source Definition

The source definition from the Administrative Part 70 Operating Permit Renewal was incorporated into the permit as follows:

This collocated airfield, aerospace vehicle maintenance center and central energy plant source consists of five (5) plants:

(a) Plant 1, Indianapolis Airport Authority (097-00156), is located at 2825 West Perimeter Road, Indianapolis, Indiana 46241 and 7800 Col. H. Weir Cook Memorial Drive (and various collocated addresses), Indianapolis, Indiana 46241;

(b) Plant 2, Johnson Melloh Solutions - IMC Central Energy Plant (097-00586), is located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241;

(c) Plant 3, AAR Aircraft Services, Indianapolis (097-00559), is located at 2825 West Perimeter Road, Indianapolis, Indiana 46241;

(d) Plant 5, Chautauqua Airlines (097-00668), is located at 2745 South Hoffman Road, Dock 67, Hangar 7A-7B, Indianapolis, IN 46241; and

(e) Plant 6, ASIG Aircraft Services International Group (097-00667), is located at 2050 Hoffman Road, Indianapolis, IN 46241.

These plants are located on one or more contiguous or adjacent properties, have the same two digit SIC code and are under common control, therefore they are considered one (1) major source, as defined by 326 IAC 2-7-1(22).

A Part 70 Operating Permit will be issued to the Indianapolis Airport Authority (097-00156) as the primary source, and Administrative Part 70 Operating Permits will be issued to Johnson Melloh Solutions – IMC Central Energy Plant (097-00586), AAR Aircraft Services, Indianapolis (097-00559), Chautauqua Airlines (097-00668) and ASIG Aircraft Services International Group (097-00667) solely for administrative purposes.

The source was initially separated into three (3) plants consisting of the Indianapolis Airport Authority (097-00156), AAR Aircraft Services, Indianapolis (097-00559) and Indianapolis Diversified Machining, Inc. (097-00560) under administrative amendment number 097-21243-00156, administrative amendment number 097-21245-00559, and administrative amendment number 097-21325-00560, all issued on October 14, 2005.

The source was reorganized into four (4) plants consisting of the Indianapolis Airport Authority (097-00156), BHMM Energy Services, LLC (097-00586), AAR Aircraft Services (097-00559), and Indianapolis Diversified Machining, Inc. (097-00560) under administrative amendment number 097-23165-00156, administrative amendment number 097-22919-00586, both issued on November 30, 2006, minor source modification number 097-25415-00559, issued on March 3, 2008, and Administrative Part 70 Operating Permit Renewal number T 097-25296-00560, issued on December 31, 2008.

The source was reorganized into six (6) plants consisting of the Indianapolis Airport Authority (097-00156), BHMM Energy Services, LLC (097-00586), AAR Aircraft Services (097-00559), Indianapolis Diversified Machining, Inc. (097-00560), Chautauqua Airlines (097-00668) and Skytanking (now ASIG Aircraft Services International Group) (097-00667) under administrative amendment number 097-25348-00156, issued on July 7, 2010, significant permit modification number 097-28213-00559, issued on March 30, 2010, and administrative amendment number 097-28370-00668, issued on July 9, 2010. Indianapolis Diversified Machining, Inc. had its permit revoked under 097-29631-00560 on September 9, 2010 and the new source definition was never incorporated into the BHMM Energy Services, LLC permit because the equipment was moved into the AAR permit.

Finally, the source was reorganized into five (5) plants consisting of the Indianapolis Airport Authority (097-00156), Johnson Melloh Solutions (097-00586), AAR Aircraft Services (097-00559), Chautauqua Airlines (097-00668) and Skytanking (now ASIG Aircraft Services International Group) (097-00667) under Part 70 Operating Permit Renewal number 097-25348-00156, issued on July 7, 2010, significant permit modification number 097-28213-00559, issued on March 30, 2010, Administrative Part 70 Operating Permit number 097-28370, issued on July 9, 2010, and 097-28369-00667, issued on July 8, 2010. On October 6, 2014, a renewal application was received from Skytanking requesting a change in ownership from Skytanking to ASIG Aircraft Services International Group. The current source description has been incorporated into the current Administrative Part 70 Operating Permit Renewal for Johnson Melloh Solutions.

Permitted Emission Units and Pollution Control Equipment

This stationary source, identified as Plant 2, located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241 consists of the following emission units and pollution control devices:

(a) Natural gas-fired Boiler #1, manufactured by Cleaver Brooks, identified as emission unit 001, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 12.6 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 001, installed in 1993.
[40 CFR 60, Subpart Dc]

(b) Natural gas-fired Boiler #2, manufactured by Cleaver Brooks, identified as emission unit 002, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 25.2 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 002, installed in 1993.
[40 CFR 60, Subpart Dc]

(c) Natural gas-fired Boiler #3, manufactured by Nebraska, identified as emission unit 003, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 003, installed in 1994.
[40 CFR 60, Subpart Db]

(d) Natural gas-fired Boiler #4, manufactured by Nebraska, identified as emission unit 004, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 004, installed in 1994.
[40 CFR 60, Subpart Db]

Insignificant Activities

This stationary source, identified as Plant 2, located at 2745 South Hoffman Road, Suite 504, Indianapolis, Indiana 46241 includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Degreasing operations that do not individually exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3-2] [326 IAC 8-3-8]

(b) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors, electrostatic precipitators, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations with uncontrolled potential to emit of less than five (5) pounds of PM-10 per hour and less than twenty five (25) pounds of PM-10 per day. [326 IAC 6.5-1-2(a)]

(c) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4]
[326 IAC 6.5-1-2(a)]

(d) Emergency Generator #1, manufactured by Cummins, model number KTA39-G4, identified as emission unit 005, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 005, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(e) Emergency Generator #2, manufactured by Cummins, model number KTA39-G4, identified as emission unit 006, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 006, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(f) Emergency Generator #3, manufactured by Cummins, model, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 007, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(g) Fire Pump Engine #1, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 008, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 008, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(h) Fire Pump Engine #2, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 009, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 009, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(i) Fire Pump Engine #3, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 010, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 010, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(j) Fire Pump Engine #4, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 011, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 011, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(k) Fire Pump Engine # 5, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 012, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 012, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

Existing Approvals

Since the issuance of the Part 70 Administrative Operating Permit Renewal T097-25314-00586 on October 15, 2009, the source has constructed or has been operating under the following additional approvals:

(a) Administrative Amendment number 097-32512-00586, issued on February 6, 2013.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the State Implementation Plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

Enforcement Issue

There are no enforcement actions related to the renewal of this Part 70 Administrative Permit.

Emission Calculations

See Appendix A of this document for detailed emission calculations.

County Attainment Status

The source is located in Marion County, Decatur and Wayne Township.

Pollutant	Designation
SO_2	Non-attainment effective October 4, 2013, for the Center Township, Perry Township, and Wayne Township. Better than national standards for the remainder of the county.
CO	Attainment effective February 18, 2000, for the part of the city of Indianapolis bounded by 11th Street on the north; Capitol Avenue on the west; Georgia Street on the south; and Delaware Street on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of Indianapolis and Marion County.
O_3	Unclassifiable or attainment effective July 20, 2012, for the 2008 8-hour ozone standard.[1]
$PM_{2.5}$	Attainment effective July 11, 2013, for the annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.

[1]Attainment effective October 18, 2000, for the 1-hour ozone standard for the Indianapolis area, including Marion County, and is a maintenance area for the 1-hour ozone National Ambient Air Quality Standards (NAAQS) for purposes of 40 CFR 51 , Subpart X*. The 1-hour designation was revoked effective June 15, 2005.

(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. Marion 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) $PM_{2.5}$
Marion County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) SO_2
U.S. EPA, in the Federal Register Notice 78 FR 47191 dated August 5, 2013, has designated Marion County, Wayne Township as nonattainment for SO_2. Therefore, SO_2 emissions were reviewed pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(e) Other Criteria Pollutants
Marion County has been classified as attainment or unclassifiable in Indiana for CO, PM_{10}, NO_2 and lead. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

This source contains a nested source (located at Plant 2, Johnson Melloh Solutions - IMC Central Energy Plant (097-00586)) consisting of a combination of fossil fuel-fired boilers totaling more than 250 MMBtu/hr or more heat input capacity. The nested source is considered one of the 28 source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions from the nested source are counted toward the determination of PSD, Emission Offset (EO), and Part 70 Permit applicability.

The remaining operations at the source are not one of the twenty-eight (28) listed source categories under 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7, however, there is an applicable New Source Performance Standard that was in effect on August 7, 1980, therefore fugitive emissions, from the affected facilities to which the New Source Performance Standard is applicable, are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability. Three (3) jet fuel storage tanks installed in 1978 and subject to 40 CFR 60, Subpart K, and located at the Indianapolis Airport Authority belong to a source category subject to a pre-1980 NSPS and all fugitive emission associated with these tanks are counted toward the determination of PSD, EO, and Part 70 Permit applicability.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the entire source (five (5) plants consisting of the Indianapolis Airport Authority (097-00156), Johnson Melloh Solutions (097-00586), AAR Aircraft Services (097-00559), Chautauqua Airlines (097-00668) and ASIG Aircraft Services International Group (097-00667).

Unrestricted Potential Emissions	
Pollutant	**Entire Source (TPY)**
PM	88.43
PM_{10}	100.05
$PM_{2.5}$	100.05
SO_2	365.47
NO_x	368.16
VOC	163.51
CO	196.53
Single HAP (Toluene)	7.17
Total HAP	16.31

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

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC and CO are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

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

Collocated Sources:	Permit Number	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-25348-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Dr.;
Johnson Melloh Solutions - IMC Central (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504;
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road;
Chautauqua Airlines (CHA)	T097-28370-00668	2745 South Hoffman Road, Dock 67, Hangar 7A-7B; and
ASIG Aircraft Services International Group (ASIG)	T097-28369-00667	2050 South Hoffman Road; Indianapolis, Indiana 46241

Potential to Emit - Nested Boilers (TPY) - One of 28 Source Categories

Process / Emission Unit	Location	PM	PM_{10}	*$PM_{2.5}$	SO_2	VOC	CO	NO_x
IMCCEP Boiler #1	JMS	6.05	14.07	14.07	86.22	6.66	85.90	83.20
IMCCEP Boiler #2	JMS							
IMCCEP Boiler #3	JMS							
IMCCEP Boiler #4	JMS							
Total for Nested Boilers		**6.05**	**14.07**	**14.07**	**86.22**	**6.66**	**85.90**	**83.20**
PSD Major Source Thresholds		**100**	**100**	**100**	**---**	**100**	**100**	**100**
Emission Offset/Nonattainment NSR Major Source Thresholds		**NA**	**NA**	**NA**	**100**	**NA**	**NA**	**NA**

* Direct $PM_{2.5}$

Potential to Emit - Total Collocated Source (TPY) - Not One of 28 Source Categories								
Source Process / Emission Unit	**Location**	**PM[(b)]**	**PM_{10}**	**$PM_{2.5}$[(a)]**	**SO_2**	**VOC**	**CO**	**NO_x**
Total for Nested Boilers	JMS	6.05	14.07	14.07	86.22	6.66	85.90	83.20
Emergency Generator EU-13	IAA	0.49	0.22	0.22	1.33	0.39	10.29	8.36
Emergency Generator EU-14	IAA	0.49	0.22	0.22	1.33	0.39	10.29	8.36
Tank A	IAA	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Emergency Generator EU-15	IAA	0.19	0.08	0.08	0.51	0.15	3.93	3.19
Emergency Generator EU-16	IAA	0.33	0.15	0.15	0.91	0.26	6.99	5.68
Emergency Generator EU-18	IAA	0.34	0.15	0.15	0.93	0.27	7.14	5.81
Emergency Generator EU-21	IAA	0.07	0.07	0.07	0.07	0.08	0.22	0.51
Emergency Generator EU-500	IAA	0.18	0.08	0.08	0.50	0.15	3.88	3.16
Degreasing	IAA	0.14	0.14	0.14	0.00	2.38	0.00	0.00
IAA Generators < 600 hp	IAA	0.30	0.30	0.30	0.28	0.00	0.91	4.24
IAA Generator Electric Vault	IAA	0.13	0.08	0.08	0.46	0.13	1.03	4.50
IAA Generator Eagle Hub	IAA	0.35	0.20	0.20	1.23	0.36	2.78	7.70
IAA Boilers < 100 MMBtu/hr	IAA	0.11	0.45	0.45	0.04	0.32	4.92	5.86
Boiler 23	IAA	0.02	0.10	0.10	0.01	0.07	1.10	1.31
Emergency Generator EU-24	IAA	0.13	0.08	0.08	0.76	0.13	1.04	2.45
IAA Natural Gas Heaters and Boiler	IAA	0.20	0.79	0.79	0.06	0.57	8.68	10.34
Emergency Generators EU-25/26	IAA	0.47	0.47	0.47	0.44	0.54	1.43	6.63
JMS Generators < 600 hp	JMS	1.30	1.30	1.30	1.22	1.51	3.99	18.52
JMS Generators > 600 hp	JMS	0.79	0.45	0.45	2.74	0.80	6.21	27.09
Ablative Coating Operation	AAR	5.25	5.25	5.25	0.00	25.00	0.00	0.00
AMU Heat and Cure Oven	AAR	0.02	0.08	0.08	0.01	0.06	0.92	1.10
Surface Coating P-2	AAR	0.92	0.92	0.92	0.00	25.00	0.00	0.00
NG Make-up Air Heating Unit B-1	AAR	0.30	1.20	1.20	0.09	0.87	13.25	15.77
Surface Coating EU-13/17/18	AAR	21.61	21.61	21.61	0.00	94.77	0.00	0.00
Chautauqua Airlines Emissions	CHA	0.00	0.00	0.00	0.00	negligible	0.00	0.00
ASIG Aircraft Services International Group : Generators > 600 hp	SKT	0.28	0.13	0.13	0.76	0.22	5.87	4.77
ASIG Aircraft Services International Group: Tanks	SKT	0.00	0.00	0.00	0.00	0.70	0.00	0.00
Total PTE of Entire Source		**40.47**	**48.60**	**48.60**	**99.90**	**162.13**	**180.78**	**228.55**
Emission Offset/NA-NSR Major Source Thresholds		**NA**	**NA**	**NA**	**100**	**NA**	**NA**	**NA**
PSD Major Source Thresholds		**250**	**250**	**250**	**---**	**250**	**250**	**250**

(a) $PM_{2.5}$ is direct $PM_{2.5}$.
(b) Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a regulated air pollutant.

HAP Emissions after Issuance	
Toluene	**7.13**
Hexane	2.80
Methyl Isobutyl Ketone	1.91
Xylene	1.64
Methyl Chloroform	0.95
Chromium	0.52
Methylene Chloride	0.41
Formaldehyde	0.24
Ethylbenzene	0.09
Other Minor HAPs	0.18
Total HAP	**15.87**

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

(a) This existing source, excluding the nested source, is not a major stationary source, under PSD (326 IAC 2-2), because no PSD 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 existing nested source is not a major stationary source, under PSD (326 IAC 2-2), because no PSD regulated pollutant, is emitted at a rate of one hundred (100) tons per year or more and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(c) This existing source is not a major stationary source under Emission Offset (326 IAC 2-3) because no nonattainment regulated pollutant is emitted at a rate of 100 tons per year or more.

(d) 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).

The potential to emit SO_2 from the nested source including IMCCEP Boilers #1 through #4 is greater than one hundred (100) tons per year. Therefore, the source has accepted the following limit to ensure SO_2 emissions from the nested source are below one hundred (100) tons per year, the PSD Major Source Thresholds for SO_2:

Nested Boiler Limit [326 IAC 2-1.1-5]

(a) The Permittee shall limit the combustion of Jet A fuel, No. 2 fuel oil and/or Jet A off spec fuel in Boiler #1, Boiler #2, Boiler #3 and Boiler #4 to a combined total of less than 4,309,356 gallons per twelve (12) consecutive month period with compliance determined at the end of each month; and

(b) The sulfur content of Jet A fuel, No. 2 fuel oil and/or Jet A fuel off spec fuel shall not exceed 0.28 weight percent.

Compliance with these limits, combined with the potential to emit SO_2 from insignificant activities at IMCCEP, and potential emissions of AAR emission units, shall limit the source-wide PTE of SO_2 to less than one hundred (100) tons per twelve (12) consecutive month period and shall render the requirements of 326 IAC 2-1.1-5 (Non Attainment New Source Review) not applicable to all the nested boilers and shall render the requirements of 326 IAC 2-1.1-5 (Non-Attainment New Source Review) not applicable to the entire source.

The potential to emit NO_x and CO are in excess of one hundred (100) tons per year for the nested source. The applicant accepted the following limit to remain below the PSD Major Source Threshold for NO_x and CO of one hundred (100) tons per year.

PSD Minor Limit [326 IAC 2-2]

(a) NO_X emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP, Plant 2, shall be limited to less than a combined total of 83.2 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(1) NO_X emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP shall be determined as follows:

$E_{NOX} = (F_{ng} \times EF_{ng})/2000 + (F_{Jet\ A/No.2} \times EF_{Jet\ A/No.2})/2000$ + CEM data (in tons per month)

Where:

E_{NOX} =	NO_X emissions in tons per month
F_{ng} =	Monthly natural gas usage in Boiler #1 and Boiler #2 in million cubic feet
EF_{ng}=	32 pounds NO_X emissions per million cubic feet natural gas burned in Boiler #1 and Boiler #2
$F_{Jet\ A/No.2}$ =	Monthly Jet A/ No. 2 fuel oil usage in Boiler #1 and Boiler #2
$EF_{Jet\ A/No.2}$ =	20 pounds NO_X emissions per thousand gallons of Jet A/No. 2 fuel oil burned in Boiler #1 and Boiler #2
CEM data=	NO_X continuous emission monitoring data converted to tons per month for Boiler #3 and Boiler #4

(b) CO emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP, Plant 2, shall be limited to less than a combined total of 85.90 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(1) CO emissions from Boiler #1, Boiler #2, Boiler #3 and Boiler #4 at IMCCEP shall be determined as follows:

$$E_{CO} = (F_{ng} \times EF_{ng})/2000 + (F_{Jet\ A/No.2} \times EF_{Jet\ A/No.2})/2000$$

Where: E_{CO} = CO emissions in tons per month
F_{ng} = Monthly natural gas usage in Boiler #1, Boiler #2, Boiler #3, and Boiler #4 in million cubic feet
EF_{ng} = 84 pounds CO emissions per million cubic feet natural gas burned in Boiler #1, Boiler #2, Boiler #3, and Boiler #4
$F_{Jet\ A/No.2}$ = Monthly Jet A/ No. 2 fuel oil usage in Boiler #1, Boiler #2, Boiler #3, and Boiler #4
$EF_{Jet\ A/No.2}$ = 5 pounds CO emissions per thousand gallons of Jet A/No. 2 fuel oil burned in Boiler #1, Boiler #2, Boiler #3, and Boiler #4

Compliance with these limits shall limit the potential to emit of CO and NO_x from all four boilers to less than one hundred (100) tons of per twelve (12) consecutive month period, each, and shall render the requirements of 326 IAC 2-2 (PSD) not applicable to the nested source

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 And 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)
Boiler #3 – SO_2	No	Yes	151.76	151.76	100	No	No
Boiler #3 – NO_x	Yes – FGR*	Yes	99.54	< 99.54	100	No	No
Boiler #4 – SO_2	No	Yes	151.76	151.76	100	No	No
Boiler #4 – NO_x	Yes - FGR*	Yes	99.54	< 99.54	100	No	No

*FGR = flue gas recirculation system

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the existing emission units as part of this Part 70 administrative permit renewal.

NSPS:

(b) **40 CFR 60, Subpart D – Standards of Performance for Fossil Fuel-Fired Steam Generators**: NSPS Subpart D applies to each fossil fuel-fired steam generating unit of more than 250 MMBtu/hr. All four boilers located at this source have design heat input capacities of less than 250 MMBtu/hr. Therefore, the requirements of 40 CFR 60, Subpart D (326 IAC 12) are not included in this permit.

(c) **40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units**: NSPS Da applies to electric utility steam generating units capable of combusting more than 250 MMBtu/hr of fossil fuel and for which construction, modification, or reconstruction commenced after September 18, 1978. All four boilers located at this source have design heat input capacities less than 250 MMBtu/hr and are not located at an electric utility. Therefore, the requirements of 40 CFR 60, Subpart Da (326 IAC 12) are not included in this permit.

(d) **40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**: Boiler #3 and Boiler #4 are subject to the Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60.40b, Subpart Db), which is incorporated by reference as 326 IAC 12, and included as Attachment B of the permit. The affected facilities to which Subpart Db applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984 and that has a design heat input capacity greater than 100 MMBtu/hr. Boilers #3 and #4 have design heat input capacities greater than 100 MMBtu/hr and were constructed after June 19, 1984. Therefore, the requirements of 40 CFR 60, Subpart Db are included in the permit. The affected facilities are listed below:

(1) Natural gas-fired Boiler #3, manufactured by Nebraska, identified as emission unit 003, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 003, installed in 1994. [40 CFR 60, Subpart Db]

(2) Natural gas-fired Boiler #4, manufactured by Nebraska, identified as emission unit 004, with the capability of firing Jet A fuel or No. 2 fuel oil only during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 122 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 004, installed in 1994. [40 CFR 60, Subpart Db]

Boiler #3 and Boiler #4 are subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b(a), (g), and (j);
(2) 40 CFR 60.41b;
(3) 40 CFR 60.42b(a), (e), (g), and (j);
(4) 40 CFR 60.43b(f), and (g);
(5) 40 CFR 60.44b(a), (h), and (i);
(6) 40 CFR 60.45b(j) and (k);
(7) 40 CFR 60.46b(a), (c), (d)(7), (e)(1), and (e)(4);
(8) 40 CFR 60.47b(f);

(9) 40 CFR 60.48b(b)(1), (c), (d), (e)(2), (f), (j)(2) and (l); and
(10) 40 CFR 60.49b(a), (b), (d)(1), (f)(1), (g), (h)(1), (h)(2)(i), (h)(3), (i), (j), (o), (r)(1), (v), and (w).

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 60, Subpart Db.

(e) **40 CFR 60, Subpart Dc – Standards of Performance for Small-Industrial-Commercial-Institutional Steam Generating Units**: Boiler #1 and Boiler #2 are subject to 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, and included as Attachment A of the permit. The affected facility to which Subpart Dc applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Boiler #1 and #2 were constructed after 1989 and have design heat input capacities of 100 MMBtu/hr or less and greater than 10 MMBtu/hr. Therefore, the requirements of 40 CFR 60, Subpart Dc are included in the permit. The affected facilities are listed below:

(1) Natural gas-fired Boiler #1, manufactured by Cleaver Brooks, identified as emission unit 001, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 12.6 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 001, installed in 1993. [40 CFR 60, Subpart Dc]

(2) Natural gas-fired Boiler #2, manufactured by Cleaver Brooks, identified as emission unit 002, with the capability of firing Jet A fuel or No. 2 fuel oil during periods of gas curtailment, gas supply interruption, startups and periodic testing pursuant to 40 CFR 63.11237, Subpart JJJJJJ, with a maximum heat input capacity of 25.2 million British thermal units (MMBtu/hr), using a flue gas recirculation system as NO_X control, exhausting to one stack, identified as stack 002, installed in 1993. [40 CFR 60, Subpart Dc]

Boiler #1 and Boiler #2 are subject to the following portions of Subpart Dc:

(1) 40 CFR 60.40c(a) and (b);
(2) 40 CFR 60.41c;
(3) 40 CFR 60.42c(d), (g), (h)(1), and (i);
(4) 40 CFR 60.44c(a), and (h);
(5) 40 CFR 60.46c(e); and
(6) 40 CFR 60.48c(a)(1), (b), (d), (e)(1), (e)(11), (f)(1), (g)(3), (i), and (j).

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 60, Subpart Dc.

(f) **40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**: This subpart applies to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005. All of the compression ignition engines located at this source were constructed prior to July 11, 2005. Therefore, the requirements of 40 CFR 60, Subpart IIII (326 IAC 12) are not included in this permit.

(g) **40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines**: This subpart applies to spark ignition engines. All of the emergency generators and fire pump engines located at this source are compression ignition. Therefore, the requirements of Subpart JJJJ (326 IAC 12) are not included in this permit.

NESHAP:

(h) **40 CFR 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:** The emergency generators, identified as Emergency Generators #1 through #3 and Fire Pump Engines #1 through #5 are subject to the National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, which is incorporated by reference as 326 IAC 20-82, and included as Attachment C of this permit. This subpart applies to owners and operators of stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. Johnson Melloh Solutions – IMC Central Energy Plant is an administratively separate Part 70 source located at an area source of HAPs and owns and operates existing stationary RICE constructed prior to June 12, 2006. Therefore, Subpart ZZZZ is included in the permit. Affected units are described below:

(1) Emergency Generator #1, manufactured by Cummins, model number KTA39-G4, identified as emission unit 005, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 005, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(2) Emergency Generator #2, manufactured by Cummins, model number KTA39-G4, identified as emission unit 006, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 006, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(3) Emergency Generator #3, manufactured by Cummins, model, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 1,505, exhausting to one stack, identified as stack 007, installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(4) Fire Pump Engine #1, manufactured by Detroit Diesel, model number DDFP-L8FA- 8189F, identified as emission unit 008, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 008, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(5) Fire Pump Engine #2, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 009, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 009, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(6) Fire Pump Engine #3, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 010, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 010, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(7) Fire Pump Engine #4, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 011, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 011, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

(8) Fire Pump Engine # 5, manufactured by Detroit Diesel, model number DDFP-L8FA-8189F, identified as emission unit 012, fired with Jet A fuel or No. 2 fuel oil, with a maximum horsepower rating of 480, exhausted out one stack, identified as stack 012, and installed in 1993. [40 CFR 63, Subpart ZZZZ] [326 IAC 6.5-1-2(a)]

Emergency Generators #1 through #3 and Fire Pump Engines #1 through #5 are subject to the following portions of Subpart ZZZZ:

(1) 40 CFR 63.6580;
(2) 40 CFR 63.6585(a), and (c);
(3) 40 CFR 63.6590(a)(1)(iii);
(4) 40 CFR 63.6595(a), and (c);
(5) 40 CFR 63.6603(a);
(6) 40 CFR 63.6605;
(7) 40 CFR 63.6612(a);
(8) 40 CFR 63.6620(a);
(9) 40 CFR 63.6625(e)(3), (f), (h), and (i);
(10) 40 CFR 63.6640(a), (b), (e), (f)(1), (f)(2)(i), and (f)(4);
(11) 40 CFR 63.6645(a)(5);
(12) 40 CFR 63.6650(f);
(13) 40 CFR 63.6655(e)(2), and (f)(2);
(14) 40 CFR 63.6660;
(15) 40 CFR 63.6665;
(16) 40 CFR 63.6670;
(17) 40 CFR 63.6675;
(18) Table 2d (Item 4); and
(19) Table 8.

The provisions of 40 CFR 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 63, Subpart ZZZZ.

(i) **40 CFR 63 Subpart T – National Emission Standards for Halogenated Solvent Cleaning**: This subpart applies to each individual batch vapor, in-line vapor, in-line cold, and batch cold solvent cleaning machines that use any solvent containing methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, or chloroform, or any combination of these HAP solvents, in a total concentration greater than 5% by weight, as a cleaning or drying agent. The degreasing operations located at this source do not use any of the listed HAP solvents. Therefore, the requirements of Subpart T (326 IAC 20-6) are not included in the permit.

(j) **40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters:** This subpart applies to owners and operators of industrial, commercial or institutional boilers located at major sources of HAPs. Johnson Melloh Solutions – IMC Central Energy Plant is an administratively separate Part 70 source located at a minor source of HAPs. Therefore, the requirements of Subpart DDDDD (326 IAC 20-95) are not included in this permit.

(k) **40 CFR 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units:** This subpart applies to each individual or group of two or more new, reconstructed, or existing coal fired or oil fired electric generating unit (EGU). An electric steam generating unit means any furnace or boiler used for combusting fossil fuel for the purpose of producing steam for the purpose of powering a generator to produce electricity or electricity and other thermal energy. The fossil fuel fired boilers at this source do not generate steam to power a generator. Therefore, the requirements of Subpart UUUUU are not included in this permit.

(l) **40 CFR 63, Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources:** This subpart applies to the owners and operators of industrial, commercial, or institutional boilers located at, or is a part of, an area source of Hazardous Air Pollutants (HAPs). This rule does not apply to gas-fired boilers as defined in 40 CFR 63.11237 of Subpart JJJJJJ. A gas-fired boiler is defined as any boiler that burns gaseous fuels, such as natural gas, process gas, coal derived gas, refinery gas, hydrogen, and biogas, not combined with any solid fuels and burns liquid fuels only during period of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel cannot exceed 48 hours during any calendar year. BHMM Energy Services submitted an initial notification pursuant to 40 CFR 63.9(b)(2) to U.S. EPA Region V on September 13, 2011 indicating all boilers located at this source meet the definition of gas-fired boilers and are not subject to the requirements of Subpart JJJJJJ. Therefore, the requirements of Subpart JJJJJJ are not included in this permit.

State Rule Applicability - Entire Source

326 IAC 1-7 (Stack Height Provisions)
This rule applies to all sources with exhaust gas stacks that have uncontrolled potential emissions of twenty-five (25) tons per year or more of SO_2 or particulate matter (PM). Boilers #2, #3, and #4 at Plant 2, Johnson Melloh Solutions - IMC Central Energy Plant (097-00586) have uncontrolled potential SO_2 emissions of greater than twenty-five (25) tons per year. Therefore, Boilers #2, #3, and #4 are subject to the stack height provisions of 326 IAC 1-7.

326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)
This source is a minor source for Prevention of Significant Deterioration (PSD) and a minor source for Emission Offset (EO). See the Potential to Emit after Issuance Section of this Technical Support Document (TSD) for a more detailed discussion.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants)
This rule applies to major sources of hazardous air pollutants (HAPS) constructed after July 27, 1997. This source is an area source of HAPs. Therefore, the requirements of 326 IAC 2-4.1 are not included in the permit.

326 IAC 2-6 (Emission Reporting)
This source, not located in Lake, Porter, or LaPorte County, is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of VOC and PM_{10} is less than 250 tons per year; and the potential to emit of CO, NO_x, and SO_2 is less than 2,500 tons per year. Therefore, pursuant to 326 IAC 2-6-3(b)(2), triennial reporting is required. An emission statement shall be submitted in accordance with the compliance schedule in 326 IAC 2-6-3 by July 1, 2017, and every three (3) years thereafter. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(2).

326 IAC 6-4 (Fugitive Dust Emissions)
This rule applies to all sources of fugitive dust emissions. This source has fugitive dust emissions; therefore, this rule applies to the source.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
This rule applies to any source of fugitive particulate matter emissions located in nonattainment areas for particulate matter as designated by the Air Pollution Control Board, except Lake County, which has potential fugitive particulate matter emissions of twenty-five (25) tons per year or more. This source does not have potential fugitive particulate matter emission of twenty-five tons per year of more. Therefore, the requirements of 326 IAC 6-5 are not included in the permit.

326 IAC 6.5 (PM Limitations Except Lake County)
326 IAC 6.5 applies to sources or facilities located in Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo, or Wayne Counties. Sources specifically listed in the rule shall comply with the limitations in 326 IAC 6.5-2 through 326 IAC 6.5-10, as applicable. Sources not specifically listed in 326 IAC 6.5-2 through 326 IAC 6.5-10 shall comply with 326 IAC 6.5-1-2, if they have the potential to emit one hundred (100) tons or more, or have actual emissions of ten (10) tons or more of particulate matter (PM). 326 IAC 6.5 does not apply to combustion units located at sources specifically listed in 326 IAC 6.5-2 through 326 IAC 6.5-10, that burn only natural gas. 326 IAC 6.5 does not apply to surface coating operations and reinforced plastic composites fabricating manufacturing processes that use dip coating, roll coating, flow coating, or brush coating, or that use less than five (5) gallons of coating a day. Finally, the requirements of 326 IAC 6.5 do not apply to processes subject to a more stringent limitation under an NSPS.

This source, located in Marion County, does not have the potential to emit one hundred (100) tons or more per year of PM. However, it does have the potential to emit ten (10) tons per year or more of PM and PM emissions are not limited below ten (10) per year. Therefore, 326 IAC 6.5 applies to Johnson Melloh Solutions – IMC Central Energy Plant and the requirements are included in the permit.

326 IAC 9 (Carbon Monoxide Emission Rules)
This rule applies to all stationary sources of carbon dioxide commencing operation after March 21, 1972 and for which an emission limit has been established in 326 IAC 9-1-2. 326 IAC 9-1-2 establishes CO emission limitations for petroleum refining operations, ferrous metal smelters, and refuse incineration and refuse burning equipment. This source does not include any emissions units subject to an emission limitation in 326 IAC 9-1-2. Therefore, the requirements of 326 IAC 9 are not included in this permit.

326 IAC 12 (New Source Performance Standards)
See Federal Rule Applicability Section of this TSD.

326 IAC 20 (Hazardous Air Pollutants)
See Federal Rule Applicability Section of this TSD.

State Rule Applicability – Individual Facilities

Boiler #1 and Boiler #2

326 IAC 3-5 (Continuous Monitoring of Emissions)
Boiler #1 and Boiler #2 are fossil fuel-fired steam generating units located in Marion County, constructed in 1993 with a heat input capacity of less than 100 MMBtu/hr but more than 10 MMBtu/hr. These units are subject to 40 CFR 60, Subpart Dc. Under Subpart Dc, they are subject to emission limitations for SO_2. The Permittee has selected compliance methods which do not require the installation of a continuous emissions monitoring system for SO_2.

Boiler #1 and Boiler #2 are not subject to the requirements of 326 IAC 3-5 because they are fossil fuel-fired steam generating units of less than 100 MMBtu/hr and are not required by 326 IAC 12 (NSPS) to continuously monitor emissions.

326 IAC 5 (Opacity Regulations)
This rule applies to opacity, not including condensed water vapor, emitted by or from a facility or source. 326 IAC 5 applies to this source and Boiler #1 and #2 are subject to the opacity limitations specified in 326 IAC 5-1-2(2).

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)
This rule establishes particulate matter emission limitations for sources of indirect heating located anywhere in the state. Sources of indirect heating located in Marion County and constructed on or after September 21, 1983 are subject to 326 IAC 6-2-4. Boiler #1 and #2 are sources of indirect heating located in Marion County and were constructed after September 21, 1982. Therefore, the boilers are subject to this rule unless a more restrictive PM limitation exists in 326 IAC 6.5 or NSPS Subpart Dc.

To determine the most restrictive emission limitation for PM, the 326 IAC 6-2 emission limitation must be calculated with the following equation:

$P_t = 1.09 / Q^{0.26}$ Where: Pt = Pounds of PM/MMBtu of heat input.
Q = Total source maximum operating capacity rating in MMBtu/hr heat input. (Q = 37.8 MMBtu/hr in 1993)

Particulate matter (PM) emissions from Boiler #1 and Boiler #2 shall not exceed 0.43 lb PM per MMBtu heat input, pursuant to 326 IAC 6-2-4.

40 CFR 60, Subpart Dc, which is incorporated as 326 IAC 12, does not include a pound per MMBtu emission limitation on PM emissions from these boilers. Therefore, 326 IAC 6-2 prevails over NSPS Subpart Dc.

326 IAC 6.5 applies to this source. Under 326 IAC 6.5-1-2(b)(2), particulate matter (PM) emissions from Boiler #1 and Boiler #2 shall not exceed 0.15 lb/MMBtu while combusting fuel oil or Jet A. Under 326 IAC 6.5-1-2(b)(3), particulate matter (PM) emissions from Boiler #1 and Boiler #2 shall not exceed 0.01 grain per dry standard cubic foot while combusting natural gas (approximately 0.012 lb/MMBtu). This analysis indicates the emission limitations contained in 326 IAC 6.5 are the most restrictive PM emission limitations. Therefore, the requirements of 326 IAC 6-2 do not apply to Boiler #1 or Boiler #2.

326 IAC 6.5 (PM Limitations Except Lake County)
Boiler #3 and Boiler #4 are subject to the requirements of 326 IAC 6.5. The following particulate matter (PM) emission limitations have been established for Boiler #1 and Boiler #2:

(a) Pursuant to 326 IAC 6.5-1-2(b)(2), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #1 and Boiler #2 shall not exceed 0.15 lb/MMBtu, each while combusting No. 2 fuel oil and Jet A fuel oil.

(b) Pursuant to 326 IAC 6.5-1-2(b)(3), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #1, and Boiler #2 shall not exceed 0.01 grain per dry standard cubic foot while combusting natural gas.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
All emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide shall comply with the emission limitations in 326 IAC 7-1.1-2, the compliance test methods in 326 IAC 2, and the sulfur dioxide emission limitations and other requirements under 326 IAC 12. Boiler #1 does not have a potential to emit sulfur dioxide of 25 tons per year or ten pounds per hour. Therefore, 326 IAC 7-1.1 does not apply to Boiler #1.

Boiler #2 does have a potential to emit SO_2 of 25 tons per year or more. Therefore, 326 IAC 7-1.1 does apply to Boiler #2. Pursuant to 326 IAC 7-1.1-2, sulfur dioxide emissions from Boiler #2 shall not exceed 0.5 pound per million Btu while combusting distillate oil (No. 2 fuel oil and Jet A).

326 IAC 24-1 (Clean Air Interstate Rule Nitrogen Oxides Annual Trading Program)
This rule establishes an annual NO_x emissions budget and annual NO_x trading program. Clean Air Interstate Rule (CAIR) NO_x units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. Boiler #1 and Boiler #2 do not serve a generator that produces electricity for sale to the grid. Therefore, the requirements of 326 IAC 24-1 are not included in the permit.

326 IAC 24-2 (Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program
This rule establishes an SO_2 emissions budget and SO_2 trading program. CAIR SO_2 units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. Boiler #1 and Boiler #2 do not serve a generator that produces electricity for sale to the grid. Therefore, the requirements of 326 IAC 24-2 are not included in the permit.

326 IAC 24-3 (Clean Air Interstate Rule (CAIR) NOx Ozone Season Trading Program)
This rule establishes a NO_x ozone season emissions budget and NO_x trading program for fossil fuel-fired generating units and large affected units. Clean Air Interstate Rule (CAIR) NO_x ozone season units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. This rule also applies to large affected units which are defined in 326 IAC 24-3-2(51) (Definitions). A large affected unit has a maximum design heat input capacity greater than 250 MMBtu/hr and served during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid. The maximum heat input capacities of Boiler #1 and Boiler #2 are each less than 250 MMBtu/hr and 326 IAC 24-3 does not apply and the requirements are not included in the permit.

326 IAC 24-4 (Clean Air Mercury Rule (CAMR) Trading Program)
This rule establishes a mercury emissions budget and mercury trading program for coal-fired generating units. Boiler #1 and Boiler #2 do not combust coal or coal-derived fuel. Therefore, the requirements of 326 IAC 24-4 are not included in this permit.

Boiler #3 and Boiler #4

326 IAC 3-5 (Continuous Monitoring of Emissions)
Boiler #3 and Boiler #4 are fossil fuel-fired steam generating units located in Marion County with a heat input capacity of greater than 100 MMBtu/hr. These units are subject to the requirements of 40 CFR 60, Subpart Db. Under Subpart Db, they are subject to emission limitations for SO_2, Opacity, and NO_x. The Permittee has selected compliance options that do not require continuous monitoring for Opacity or SO_2. However, both boilers are required by Subpart Db to continuously monitor NO_x emissions.

Pursuant to 326 IAC 3-5-1(a)(2), all fossil fuel-fired steam generating units of greater than 100 MMBtu/hr heat input are subject to the requirements of 326 IAC 3-5. An opacity monitor is not required for these boilers because oil or a mix of gas and oil are the only fuels combusted and the boilers can comply with the requirements of 326 IAC 5-1 (Opacity), 326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating) without the use of particulate matter collection equipment. Therefore, an opacity monitor is not required pursuant to 326 IAC 3-5-1(b)(2)(A)(ii).

Pursuant to 326 IAC 3-5-1(b)(2)(B), a continuous monitor for SO_2 is not required because SO_2 control equipment has not been installed, and a monitor is not required by 326 IAC 12 (NSPS) or a new construction permit or operating permit under 326 IAC 2.

Pursuant to 326 IAC 3-5-1(b)(2)(C), a continuous monitor for NO_x is required because NO_x control equipment has been installed, and a continuous monitor is required by 326 IAC 12 (NSPS).

Pursuant to 326 IAC 3-5-1(b)(2)(D), a continuous monitor for O_2 or CO_2 is required if measurements of either is required to convert SO_2 or NO_x continuous monitoring data to the units of an emission limitation. The Permittee has installed a CO_2 monitor to convert NO_x continuous monitoring data to lb/MMBtu.

A CO CEMS was voluntarily installed on Boiler #3 and Boiler #4 in order to resolve alleged prevention of significant deterioration (PSD) violations with the City of Indianapolis, Office of Environmental Services (OES) and IDEM, OAQ. The construction of Boiler #3 and #4 in the early 1990's constituted a major modification under PSD for NO_x and SO_2 and PSD permitting was required prior to construction or PSD minor limits should have been established in the operating permit. Although the Indianapolis Airport Authority could have operated above the PSD major source threshold, they never did. In addition to the installation of the CO CEMS, the Indianapolis Airport Authority accepted minor limits on fuel oil combustion and NO_x and CO emissions for Boiler #1, #2, #3 and #4. These limits ensure the source operates under the PSD major source thresholds.

The applicant has requested the removal of permit conditions requiring the use of a CO CEMS on Boiler #3 and Boiler #4 as part of this permitting action. They proposed to show compliance with the CO PSD minor limit using AP-42 emission factors in place of CO CEMS data. IDEM, OAQ has reviewed this request and concurs with removal of the permit requirements for a CO CEMS because:

(1) The use of a CEMS to monitor CO emissions from Boiler #3 and Boiler #4 is not required by 326 IAC 3-5, 326 IAC 12 (NSPS) or 326 IAC 20 (NESHAP), or any other state or federal rule.

(2) Relative Accuracy Test Audits (RATAs) conducted by the source between 2008 and 2011 on Boiler #3 and Boiler #4 while combusting natural gas indicate a range of CO emission rates from a low of 0.0 ppm to a high of 33.3 ppm (24.79 lb/MMCF). The AP-42 emission factor for a post-NSPS boiler combusting natural gas is 84 lb/MMCF. The highest recorded emission rate (24.79 lb/MMCF) over a three year period was 29.5% of the AP-42 emission factor.

(3) The total unlimited PTE of CO for the IMCCEP Boilers #1 through #4 assuming natural gas combustion and using AP-42 emission factors is 101.65 TPY. These boilers could operate 359 days at full capacity and still remain under the PSD major source threshold. However, some of the boilers are primarily used to provide heat during the winter months and it is reasonable to assume all four boilers will never approach 8,760 hours of operation at full capacity as a practical matter.

(4) Emissions statements submitted to IDEM, OAQ report actual CO emissions as follows:

CO Emissions – Total for IMCCEP Boiler #1 through #4		
Month	**Year**	**Rolling 12 Month Total CO Emissions (tons/12-consecutive month period)**
March	2014	0.98
February	2014	1.11
January	2014	1.13
December	2013	1.66
November	2013	2.11
October	2013	2.19
September	2013	2.44
August	2013	2.44
July	2013	2.44
March	2013	2.19
February	2013	2.26
January	2013	2.31
December	2012	1.79
September	2012	1.36
August	2012	1.36
July	2012	1.32
June	2012	1.36
May	2012	1.36
April	2012	1.63
March	2012	2.06
February	2012	2.66
January	2012	2.95
December	2011	3.47
November	2011	4.78
October	2011	5.19
September	2011	4.92
August	2011	4.95
July	2011	5.04

CO Emissions – Total for IMCCEP Boiler #1 through #4		
Month	**Year**	**Rolling 12 Month Total CO Emissions (tons/12-consecutive month period)**
June	2011	5.05
May	2011	5.29
April	2011	5.28
March	2011	5.20
February	2011	4.76
January	2011	4.50
December	2010	4.53
November	2010	4.44
October	2010	4.44
September	2010	5.07
August	2010	5.00
July	2010	4.91
June	2010	4.90
May	2010	4.66
April	2010	4.39
March	2010	4.05
February	2010	3.65
January	2010	3.52

The twelve month rolling CO emissions are significantly below the PSD Minor Limit for CO of 85.90 tons of CO per twelve consecutive month period for the IMCCEP Boilers #1 through #4.

IDEM, OAQ is no longer requiring the use of a CO CEMS on Boiler #3 and Boiler #4. The Permittee can document and report compliance with the PSD Minor Limit for CO using standard emission AP-42 factors.

326 IAC 5 (Opacity Regulations)
This rule applies to opacity, not including condensed water vapor, emitted by or from a facility or source. 326 IAC 5 does not apply to facilities for which specific opacity limitations have been established by an NSPS, which are incorporated as 326 IAC 12. In the case of Boiler #3 and Boiler #4, 40 CFR 60, Subpart Db established an opacity standard. Therefore, 326 IAC 5 applies to the source but not to Boiler #3 or Boiler #4. The more restrictive opacity requirements under Subpart Db shall apply.

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)
This rule establishes particulate matter emission limitations for sources of indirect heating located anywhere in the state. Sources of indirect heating located in Marion County and constructed on or after September 21, 1983 are subject to 326 IAC 6-2-4. Boiler #3 and #4 are sources of indirect heating located in Marion County and were constructed after September 21, 1982. Therefore, the boilers are subject to this rule unless a more restrictive PM limitation exists in 326 IAC 6.5 or NSPS Subpart Db.

To determine the most restrictive emission limitation for PM, the 326 IAC 6-2 emission limitation must be calculated with the following equation:

$P_t = 1.09 / Q^{0.26}$ Where: Pt = Pounds of PM/MMBtu of heat input.
Q = Total source maximum operating capacity rating in MMBtu/hr heat input. (Q = 281.1 MMBtu/hr in 1994)

Particulate matter (PM) emissions from Boiler #3 and Boiler #4 shall not exceed 0.25 lb PM per MMBtu heat input, pursuant to 326 IAC 6-2-4.

40 CFR 60, Subpart Db, which is incorporated as 326 IAC 12, does not include an emission limitation on PM emissions from these boilers. Therefore, Subpart Db is not more restrictive than 326 IAC 6-2.

326 IAC 6.5 applies to this source. Under 326 IAC 6.5-1-2(b)(2), particulate matter (PM) emissions from Boiler #3 and Boiler #4 shall not exceed 0.15 lb/MMBtu while combusting fuel oil or Jet A. Under 326 IAC 6.5-1-2(b)(3), particulate matter (PM) emissions from Boiler #3 and Boiler #4 shall not exceed 0.01 grain per dry standard cubic foot while combusting natural gas (0.012 lb/MMBtu). This analysis indicates the emission limitations contained in 326 IAC 6.5 are the most restrictive PM emission limitations. Therefore, the requirements of 326 IAC 6-2 do not apply to Boiler #3 or Boiler #4.

326 IAC 6.5 (PM Limitations Except Lake County)
Boiler #3 and Boiler #4 are subject to the requirements of 326 IAC 6.5. The following particulate matter (PM) emission limitations have been established for Boiler #3 and Boiler #4:

(a) Pursuant to 326 IAC 6.5-1-2(b)(2), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #3 and Boiler #4 shall not exceed 0.15 lb/MMBtu, each while combusting No. 2 fuel oil and Jet A fuel oil.

(b) Pursuant to 326 IAC 6.5-1-2(b)(3), particulate matter (PM) emissions from the fuel combustion steam generators, identified as Boiler #3, and Boiler #4 shall not exceed 0.01 grain per dry standard cubic foot while combusting natural gas.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
All emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide shall comply with the emission limitations in 326 IAC 7-1.1-2, the compliance test methods in 326 IAC 2, and the sulfur dioxide emission limitations and other requirements under 326 IAC 12.

Boiler #3 and Boiler #4 do have the potential to emit SO_2 of 25 tons per year or more, each. Therefore, 326 IAC 7-1.1 does apply to Boiler #3 and Boiler #4. Pursuant to 326 IAC 7-1.1-2, sulfur dioxide emissions from Boiler #3 and Boiler #4 shall not exceed 0.5 pound per million Btu, each, while combustion distillate oil, consisting of No. 2 fuel oil and Jet A.

326 IAC 24-1 (Clean Air Interstate Rule Nitrogen Oxides Annual Trading Program)
This rule establishes an annual NO_x emissions budget and annual NO_x trading program. Clean Air Interstate Rule (CAIR) NO_x units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. Boiler #3 and Boiler #4 do not serve a generator that produces electricity for sale to the grid. Therefore, the requirements of 326 IAC 24-1 are not included in the permit.

326 IAC 24-2 (Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program
This rule establishes an SO_2 emissions budget and SO_2 trading program. CAIR SO_2 units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. Boiler #3 and Boiler #4 do not serve a generator that produces electricity for sale to the grid. Therefore, the requirements of 326 IAC 24-2 are not included in the permit.

326 IAC 24-3 (Clean Air Interstate Rule (CAIR) NOx Ozone Season Trading Program)
This rule establishes a NO_x ozone season emissions budget and NO_x trading program for fossil fuel-fired generating units and large affected units. Clean Air Interstate Rule (CAIR) NO_x ozone season units include any stationary fossil fuel-fired boiler or combustion turbine serving a generator with a nameplate capacity of twenty-five (25) megawatt electrical producing electricity for sale. This rule also applies to large affected units which are defined in 326 IAC 24-3-2(51) (Definitions). The maximum heat input capacities of Boiler #3 and Boiler #4 are each less than 250 MMBtu/hr and 326 IAC 24-3 does not apply and the requirements are not included in the permit.

326 IAC 24-4 (Clean Air Mercury Rule (CAMR) Trading Program)
This rule establishes a mercury emissions budget and mercury trading program for coal-fired generating units. Boiler #1 and Boiler #2 do not combust coal or coal-derived fuel and are not generating units. Therefore, the requirements of 326 IAC 24-4 are not included in this permit.

Degreasing Operations

326 IAC 8-3 (Organic Solvent Degreasing Operations)
This rule applies to owners and operators of degreasers using solvents that contain one (1) or more volatile organic compounds. Degreasers using a solvent containing less than one percent (1%) of VOC by weight and degreasers subject to 40 CFR 63, Subpart T (National Emission Standards for Hazardous Air Pollutants for Halogenated Solvent Cleaning) are exempt from 326 IAC 8-3. The degreasing operations at this source are subject to the requirements of 326 IAC 8-3 and they are included in the permit.

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), the Permittee shall ensure the following control equipment and operating requirements are met for each degreaser constructed after January 1, 1980:

(a) Equip the degreaser with a cover;

(b) Equip the degreaser with a device for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the degreaser;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements; and

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

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, material requirements for cold cleaner degreasers are as follows:

(a) The Permittee shall not cause or allow the sale of solvents for use in cold cleaner degreasing operations with a VOC composite partial vapor pressure, when diluted at the manufacturer's recommended blend and dilution, that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit) in an amount greater than five (5) gallons during any seven (7) consecutive days to an individual or business.

(b) The Permittee shall not operate the cold cleaner degreasers with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

(c) The Permittee shall maintain the following records for each purchase:

(1) The name and address of the solvent supplier

(2) The date of purchase (or invoice/bill date of contract servicer indicating service date;

(3) The type of solvent purchased;

(4) The total volume of solvent purchased;

(5) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

326 IAC 8-6-1 (Organic Solvent Emission Limitations)
This rule applies to existing sources, as of January 1, 1980, locate in Lake and Marion Counties, and sources commencing construction after October 7, 1974, and prior to January 1, 1980, and located anywhere in the state, with potential VOC emissions of one hundred (100) tons per year or more and not regulated by another Article 8 rule. The organic solvent degreasing operations were constructed after January 1, 1980 and are subject to 326 IAC 8-3. Therefore, the requirements of 326 IAC 8-6-1 are not included in this permit.

326 IAC 8-17 (Industrial Solvent Cleaning Operations)
This rule applies to industrial sources located in Lake or Porter Counties that use solvent cleaning in the production, repair, maintenance, or servicing of a listed operation. This source is located in Marion County. Therefore, the requirements of 326 IAC 8-17 are not included in this permit.

Miscellaneous Grinding and Machining Operations

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
This rule establishes particulate matter (PM) emission limitations for manufacturing processes located anywhere in the state. 326 IAC 6-3 does not apply if a particulate matter emission limitation established in 326 IAC 6.5 is as stringent as or more stringent than 326 IAC 6-3. The grinding and machining operations are subject to a more stringent PM emission limitation under 326 IAC 6.5. Therefore, the requirements of 326 IAC 6-3 are not included in this permit.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
This rule establishes particulate matter (PM) emission limitations for sources or facilities located in the counties of Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo, or Wayne Counties that are specifically listed in 326 IAC 6.5-2 through 10, or that have the potential to emit one hundred (100) tons or more or actual emissions of ten (10) tons or more of PM. This source is subject to 326 IAC 6.5; therefore, the grinding and machining operations are subject to 326 IAC 6.5 and the requirements are included in this permit. Pursuant to 326 IAC 6.5(a), particulate matter emissions from the grinding and machining operations shall not exceed 0.03 grain per dry standard cubic foot (dscf).

Emergency Generators and Fire Pump Engines

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)
This rule establishes particulate matter (PM) emission limitations for manufacturing processes located anywhere in the state. A manufacturing process is defined as any single or series of actions, operations, or treatments in which a mechanical, physical, or chemical transformation of material occurs that emits, or has the potential to emit, PM in the production of a product. The term includes transference, conveyance, or repair of a product. The emergency generators and fire pump engines do not meet the definition of a manufacturing process and are subject to a more restrictive PM limitation under 326 IAC 6.5. Therefore, the requirements of 326 IAC 6-3 are not included in the permit.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
This rule establishes particulate matter (PM) emission limitations for sources or facilities located in the counties of Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo, or Wayne Counties that are specifically listed in 326 IAC 6.5-2 through 10, or that have the potential to emit one hundred (100) tons or more or actual emissions of ten (10) tons or more of PM. This source is subject to 326 IAC 6.5. Therefore, the requirements of 326 IAC 6.5 are included in the permit. Pursuant to 326 IAC 6.5-1-2(a), PM emissions from each fire pump engine and generator shall not exceed 0.03 grain per dry standard cubic foot (dscf).

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
This rule establishes SO_2 emission limitations for all emission units with a potential to emit twenty-five (25) tons per year or ten (10) pounds per hour of sulfur dioxide. None of the emergency generators or fire pump engines has the potential to emit SO_2 in excess of twenty-five (25) tons per year or ten (10) pounds per hour. Therefore, the requirements of 326 IAC 7-1.1 are not included in this permit.

326 IAC 10-5 (Nitrogen Oxide Reduction Program for Internal Combustion Engines)
This rule establishes requirements for large NO_x SIP Call engines. A large NO_x SIP Call engine means a stationary internal combustion engine identified and designated as large in the NO_x SIP Call engine inventory as emitting more than one (1) ton of NO_x per average ozone season day in 1995. None of the emergency generators or fire pump engines are large NO_x SIP Call engines. Therefore, the requirements of 326 IAC 10-5 are not included in the permit.

Paved and Unpaved Roads and Parking Lots with Public Access

326 IAC 6-4 (Fugitive Dust Emissions)
This rule applies to all sources of fugitive dust. Fugitive dust is defined under 326 IAC 6-4-1 as the generation of particulate matter to the extent that some of the material escapes beyond the property line or boundaries of the property, right-of-way, or an easement on which the source is located. This source has sources of fugitive dust that may escape the property line or boundary. Therefore, 326 IAC 6-4 applies to the paved and unpaved roads and parking lots located at this source and the requirements are included in the permit.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
This rule applies to any source of fugitive particulate matter emissions located in nonattainment areas for particulate matter as designated by the board which has potential fugitive particulate matter emissions of twenty-five (25) tons per year or more. IDEM, OAQ determined under T097-9602-00156 for the United Airlines Indianapolis Maintenance Facility, that 326 IAC 6-5 did not apply because potential fugitive particulate matter emissions are less than twenty-five (25) tons per year.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
326 IAC 6.5 applies to this source. Therefore, all paved and unpaved roads and parking lots with public access shall comply with the requirements of 326 IAC 6.5. Pursuant to 326 IAC 6.5-1-2(a), particulate matter emissions from all paved and unpaved roads and parking lots with public access shall not exceed 0.03 grain per dry standard cubic foot.

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 this source are as follows:

Compliance Determination Requirements		
Emission Unit	**Parameter**	**Frequency**
Boilers #1 through #4	SO_2 Emissions, Fuel Oil Sulfur Content	Each delivery
Boilers #3 and #4	NO_x Emissions	Continuous
Grinding and Machining Operations	Use of Particulate Matter (PM) Control Device	At all times

The compliance monitoring requirements applicable to this source are as follows:

Summary of Monitoring Requirements			
Emission Units	**Parameter**	**Frequency**	**Response to Excursions or Exceedances**
Boilers #1 through #4	VE Notations	Once per day while combusting fuel oil.	A Reasonable Response

These monitoring conditions are necessary to ensure proper combustion and compliance with 326 IAC 6.5.

Recommendation

The staff recommends to the Commissioner that the Part 70 Administrative Operating Permit Renewal be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on January 14, 2014.

Conclusion

The operation of this stationary aerospace vehicle maintenance center and central energy plant shall be subject to the conditions of the attached Part 70 Administrative Operating Permit Renewal No. T097-34078-00586.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to David Matousek at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 232-8253 or toll free at 1-800-451-6027 extension 2-8253.

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

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the internet at: http://www.in.gov/idem/5881.htm and the Citizens' Guide to IDEM on the internet at http://www.in.gov/idem/6900.htm.

Appendix A to the Technical Support Document - Emission Calculations
PSD Analysis - Entire Source after Issuance

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Potential to Emit - Nested Boilers (TPY) - One of 28 Source Categories								
Process / Emission Unit	**Location**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NO_x**
IMCCEP Boiler #1	JMS	6.05	14.07	14.07	86.22	6.66	85.90	83.20
IMCCEP Boiler #2	JMS							
IMCCEP Boiler #3	JMS							
IMCCEP Boiler #4	JMS							
Total for Nested Boilers		**6.05**	**14.07**	**14.07**	**86.22**	**6.66**	**85.90**	**83.20**
PSD Major Source Thresholds		**100**	**100**	**100**	**100**	**100**	**100**	**100**

Potential to Emit - Total Collocated Source (TPY) - Not One of 28 Source Categories								
Source Process / Emission Unit	**Location**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**	**CO**	**NO_x**
Total for Nested Boilers	JMS	6.05	14.07	14.07	86.22	6.66	85.90	83.20
Emergency Generator EU-13	IAA	0.49	0.22	0.22	1.33	0.39	10.29	8.36
Emergency Generator EU-14	IAA	0.49	0.22	0.22	1.33	0.39	10.29	8.36
Tank A	IAA	0.00	0.00	0.00	0.00	0.36	0.00	0.00
Emergency Generator EU-15	IAA	0.19	0.08	0.08	0.51	0.15	3.93	3.19
Emergency Generator EU-16	IAA	0.33	0.15	0.15	0.91	0.26	6.99	5.68
Emergency Generator EU-18	IAA	0.34	0.15	0.15	0.93	0.27	7.14	5.81
Emergency Generator EU-21	IAA	0.07	0.07	0.07	0.07	0.08	0.22	0.51
Emergency Generator EU-500	IAA	0.18	0.08	0.08	0.50	0.15	3.88	3.16
Degreasing	IAA	0.14	0.14	0.14	0.00	2.38	0.00	0.00
IAA Generators < 600 hp	IAA	0.30	0.30	0.30	0.28	0.00	0.91	4.24
IAA Generator Electric Vault	IAA	0.13	0.08	0.08	0.46	0.13	1.03	4.50
IAA Generator Eagle Hub	IAA	0.35	0.20	0.20	1.23	0.36	2.78	7.70
IAA Boilers < 100 MMBtu/hr	IAA	0.11	0.45	0.45	0.04	0.32	4.92	5.86
Boiler 23	IAA	0.02	0.10	0.10	0.01	0.07	1.10	1.31
Emergency Generator EU-24	IAA	0.13	0.08	0.08	0.76	0.13	1.04	2.45
IAA Natural Gas Heaters and Boiler	IAA	0.20	0.79	0.79	0.06	0.57	8.68	10.34
Emergency Generators EU-25/26	IAA	0.47	0.47	0.47	0.44	0.54	1.43	6.63
JMS Generators < 600 hp	JMS	1.30	1.30	1.30	1.22	1.51	3.99	18.52
JMS Generators > 600 hp	JMS	0.79	0.45	0.45	2.74	0.80	6.21	27.09
Ablative Coating Operation	AAR	5.25	5.25	5.25	0.00	25.00	0.00	0.00
AMU Heat and Cure Oven	AAR	0.02	0.08	0.08	0.01	0.06	0.92	1.10
Surface Coating P-2	AAR	0.92	0.92	0.92	0.00	25.00	0.00	0.00
NG Make-up Air Heating Unit B-1	AAR	0.30	1.20	1.20	0.09	0.87	13.25	15.77
Surface Coating EU-13/17/18	AAR	21.61	21.61	21.61	0.00	94.77	0.00	0.00
Chautauqua Airlines Emissions	CHA	0.00	0.00	0.00	0.00	negligible	0.00	0.00
ASIG Aircraft Services International Group : Generators > 600 hp	ASIG	0.28	0.13	0.13	0.76	0.22	5.87	4.77
ASIG Aircraft Services International Group: Tanks	ASIG	0.00	0.00	0.00	0.00	0.70	0.00	0.00
Total PTE of Entire Source		**40.47**	**48.60**	**48.60**	**99.90**	**162.13**	**180.78**	**228.55**
Emission Offset/NA-NSR		**---**	**---**	**---**	**100.00**	**---**	**---**	**---**
PSD Major Source Thresholds		**250**	**250**	**250**	**---**	**250**	**250**	**250**

Appendix A to the Technical Support Document - Emission Calculations
Indianapolis Airport Authority - HAP Emissions After Issuance

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Indianapolis Airport Authority HAP Summary

HAP	EU13	EU14	EU15	EU16	EU18	EU21	EU500	Degrease	Gen < 600	Electric Vault Generator	Eagle Hub Generator	Boiler < 100	Boiler 23	Gen 024	NG Heaters <100	Gen 025/026	IAA Total
1,1,1-Trichloroethane																	
1,3-butadiene									3.76E-05							5.86E-05	**9.62E-05**
2-methylnaphthalene																	
3-methylchloranthrene																	
7,12-dimethylbenz(a)anthracene																	
Acenaphthene																	
Acenaphthylene																	
Acetaldehyde	9.70E-05	9.70E-05	3.70E-05	6.59E-05	6.74E-05	1.79E-04	3.66E-05		7.38E-04	3.31E-05	8.93E-05			3.33E-05		1.15E-03	**2.62E-03**
Acrolein	3.03E-05	3.03E-05	1.16E-05	2.06E-05	2.11E-05	2.15E-05	1.15E-05		8.90E-05	1.03E-05	2.79E-05			1.04E-05		1.39E-04	**4.23E-04**
Anthracene																	
Arsenic																	
Benz(a)anthracene																	
Benzene	2.99E-03	2.99E-03	1.14E-03	2.03E-03	2.08E-03	2.17E-04	1.13E-03		8.98E-04	1.02E-03	2.75E-03	1.23E-04	2.76E-05	1.03E-03	2.17E-04	1.40E-03	**0.02**
Benzo(a)pyrene																	
Benzo(b)fluoranthene																	
Benzo(g,h,i)perylene																	
Benzo(k)fluoranthene																	
Beryllium																	
Cadmium												6.44E-05	1.45E-05		1.14E-04		**1.93E-04**
Chromium												8.20E-05	1.84E-05		1.45E-04		**2.45E-04**
Chrysene																	
Dibenzo(a,h)anthracene																	
Dichlorobenzene												7.03E-05	1.58E-05		1.24E-04		**2.10E-04**
Diisocyanate																	
Ethylbenzene								7.45E-02									**0.07**
Fluoranthene																	
Fluorene																	
Formaldehyde	3.04E-04	3.04E-04	1.16E-04	2.06E-04	2.11E-04	2.75E-04	1.15E-04		1.14E-03	1.04E-04	2.80E-04	4.39E-03	9.86E-04	1.04E-04	7.75E-03	1.77E-03	**0.02**
Glycol																	
Hexane												1.05E-01	2.37E-02		1.86E-01		**0.32**
Indo(1,2,3-cd)pyrene																	
Lead												2.93E-05	6.57E-06		5.17E-05		**8.75E-05**
Manganese												2.23E-05	4.99E-06		3.93E-05		**6.65E-05**
Mercury																	
Methanol																	
Methyl Chloroform																	
Methyl Isobutyl Ketone																	
Methylene Chloride																	
Naphthalene																	
Nickel												1.23E-04	2.76E-05		2.17E-04		**3.68E-04**
Phenanthrene																	
Phenol																	
Polycyclic Organic Matter	8.16E-04	8.16E-04	3.12E-04	5.55E-04	5.67E-04	3.92E-05	3.08E-04		1.62E-04	2.78E-04	7.51E-04			2.80E-04		2.52E-04	**5.14E-03**
Pyrene																	
Selenium																	
Toluene	1.08E-03	1.08E-03	4.13E-04	7.35E-04	7.51E-04	9.51E-05	4.09E-04	6.16E-01	3.94E-04	3.69E-04	9.96E-04	1.99E-04	4.47E-05	3.71E-04	3.52E-04	6.13E-04	**0.62**
Trimethylpentane																	**0.00**
Xylene	7.43E-04	7.43E-04	2.84E-04	5.05E-04	5.16E-04	6.65E-05	2.81E-04	1.68E-01	2.74E-04	2.53E-04	6.84E-04			2.55E-04		4.27E-04	**0.17**
Process Total	**6.06E-03**	**6.06E-03**	**2.31E-03**	**4.12E-03**	**4.21E-03**	**8.93E-04**	**2.29E-03**	**0.86**	**3.73E-03**	**2.07E-03**	**5.58E-03**	**0.11**	**0.02**	**2.08E-03**	**0.20**	**5.80E-03**	**1.23**

Appendix A to the Technical Support Document - Emission Calculations
Sourcewide HAP Emissions After Issuance - Including Nested Source

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Sourcewide HAP Emissions

HAP	JMS IMCCEP Boilers	JMS Gen < 600	JMS Gen > 600	AAR Ablative	AAR AMU Oven	AAR P-2	AAR B-1	AAR EU13, 17, 18	Total from CHA	ASIG Generator	ASIG Tanks	Subtotal	IAA Total	Source Total
1,1,1-Trichloroethane	5.09E-04											5.09E-04	0.00E+00	**5.09E-04**
1,3-butadiene		1.64E-04										1.64E-04	9.62E-05	**2.60E-04**
2-methylnaphthalene	2.90E-05											2.90E-05	0.00E+00	**2.90E-05**
3-methylchloranthrene	2.18E-06											2.18E-06	0.00E+00	**2.18E-06**
7,12-dimethylbenz(a)anthracene	1.94E-05											1.94E-05	0.00E+00	**1.94E-05**
Acenaphthene	4.71E-05											4.71E-05	0.00E+00	**4.71E-05**
Acenaphthylene	2.19E-06											2.19E-06	0.00E+00	**2.19E-06**
Acetaldehyde		3.22E-03	1.99E-04							5.54E-05		3.48E-03	2.62E-03	**0.01**
Acrolein		3.89E-04	6.23E-05							1.73E-05		4.68E-04	4.23E-04	**8.91E-04**
Anthracene	4.83E-06											4.83E-06	0.00E+00	**4.83E-06**
Arsenic	1.39E-03											1.39E-03	0.00E+00	**1.39E-03**
Benz(a)anthracene	1.03E-05											1.03E-05	0.00E+00	**1.03E-05**
Benzene	2.54E-03	3.92E-03	6.13E-03		2.30E-05		3.31E-04			1.71E-03		0.01	0.02	**0.03**
Benzo(a)pyrene	1.45E-06											1.45E-06	0.00E+00	**1.45E-06**
Benzo(b)fluoranthene	2.18E-06											2.18E-06	0.00E+00	**2.18E-06**
Benzo(g,h,i)perylene	5.97E-06											5.97E-06	0.00E+00	**5.97E-06**
Benzo(k)fluoranthene	2.18E-06											2.18E-06	0.00E+00	**2.18E-06**
Beryllium	9.13E-04											9.13E-04	0.00E+00	**9.13E-04**
Cadmium	1.91E-03				1.20E-05		1.73E-04					2.09E-03	1.93E-04	**2.29E-03**
Chromium	2.18E-03				1.53E-05		2.21E-04	5.20E-01				0.52	2.45E-04	**0.52**
Chrysene	6.78E-06											6.78E-06	0.00E+00	**6.78E-06**
Dibenzo(a,h)anthracene	4.70E-06											4.70E-06	0.00E+00	**4.70E-06**
Dichlorobenzene	1.45E-03				1.31E-05		1.89E-04					1.65E-03	2.10E-04	**1.86E-03**
Diisocyanate								1.00E-02				0.01	0.00E+00	**0.01**
Ethylbenzene	1.37E-04			6.94E-03				1.00E-02				0.02	0.07	**0.09**
Fluoranthene	1.32E-05											1.32E-05	0.00E+00	**1.32E-05**
Fluorene	1.22E-05											1.22E-05	0.00E+00	**1.22E-05**
Formaldehyde	2.00E-01	4.96E-03	6.23E-04		8.21E-04		1.18E-02			1.73E-04		0.22	0.02	**0.24**
Glycol								1.00E-02				0.01	0.00E+00	**0.01**
Hexane	2.18E+00				1.97E-02		2.84E-01					2.48	0.32	**2.80**
Indo(1,2,3-cd)pyrene	6.26E-06											6.26E-06	0.00E+00	**6.26E-06**
Lead	2.71E-03				5.48E-06		7.88E-05					2.79E-03	8.75E-05	**2.88E-03**
Manganese	2.15E-03				4.16E-06		5.99E-05					2.22E-03	6.65E-05	**2.28E-03**
Mercury	1.14E-03											1.14E-03	0.00E+00	**1.14E-03**
Methanol								1.00E-02				1.00E-02	0.00E+00	**0.01**
Methyl Chloroform								9.50E-01				0.95	0.00E+00	**0.95**
Methyl Isobutyl Ketone				1.19E+00		3.97E-01		3.20E-01				1.91	0.00E+00	**1.91**
Methylene Chloride								4.10E-01				0.41	0.00E+00	**0.41**
Naphthalene	2.99E-03											2.99E-03	0.00E+00	**2.99E-03**
Nickel	2.82E-03				2.30E-05		3.31E-04					3.18E-03	3.68E-04	**3.55E-03**
Phenanthrene	3.82E-05											3.82E-05	0.00E+00	**3.82E-05**
Phenol								8.00E-02				0.08	0.00E+00	**0.08**
Polycyclic Organic Matter	7.11E-03	7.06E-04	1.68E-03							4.66E-04		0.01	5.14E-03	**0.02**
Pyrene	1.37E-05											1.37E-05	0.00E+00	**1.37E-05**
Selenium	4.73E-04											4.73E-04	0.00E+00	**4.73E-04**
Toluene	1.67E-02	1.72E-03	2.22E-03	5.56E+00	3.72E-05		5.36E-04	9.20E-01		6.18E-04		6.51	0.62	**7.13**
Trimethylpentane												0.00	0.00	**0.00**
Xylene	2.35E-04	1.20E-03	1.52E-03	7.94E-01		4.39E-01		2.30E-01		4.24E-04		1.47	0.17	**1.64**
Process Total	**2.43**	**0.02**	**0.01**	**7.56**	**0.02**	**0.84**	**0.30**	**3.47**	**0.00**	**3.46E-03**	**0.00E+00**	**14.64**	**1.23**	**15.87**

Appendix A to the Technical Support Document - Emission Calculations
Sourcewide Limited Potential to Emit

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Summary of Potential to Emit

		Limited Potential To Emit (ton/yr)							HAP	
Process / Emission Unit	Location	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	VOC	CO	Total	Single
Emergency Diesel Generator EU-13	IAA	0.49	0.22	0.22	1.33	8.36	0.39	10.29	6.06E-03	2.99E-03
Emergency Diesel Generator EU-14	IAA	0.49	0.22	0.22	1.33	8.36	0.39	10.29	6.06E-03	2.99E-03
Tank A	IAA	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00
Emergency Diesel Generator EU-15	IAA	0.19	0.08	0.08	0.51	3.19	0.15	3.93	2.31E-03	1.14E-03
Emergency Diesel Generator EU-16	IAA	0.33	0.15	0.15	0.91	5.68	0.26	6.99	4.12E-03	2.03E-03
Emergency Diesel Generator EU-18	IAA	0.34	0.15	0.15	0.93	5.81	0.27	7.14	4.21E-03	2.08E-03
Emergency Diesel Generator EU-21	IAA	0.07	0.07	0.07	0.07	0.51	0.08	0.22	8.93E-04	2.75E-04
Emergency Diesel Generator EU-500	IAA	0.18	0.08	0.08	0.50	3.16	0.15	3.88	2.29E-03	1.13E-03
Degreasing	IAA	0.14	0.14	0.14	0.00	0.00	2.38	0.00	0.86	0.62
Generators < 600 hp	IAA	0.30	0.30	0.30	0.28	4.24	0.00	0.91	3.73E-03	8.98E-04
Generators > 600 hp, Elec Vault	IAA	0.13	0.08	0.08	0.46	4.50	0.13	1.03	2.07E-03	1.02E-03
Generators > 600 hp, Eagle Hub	IAA	0.35	0.20	0.20	1.23	7.70	0.36	2.78	5.58E-03	2.75E-03
Boilers < 100 mmBtu/hr	IAA	0.11	0.45	0.45	0.04	5.86	0.32	4.92	0.11	0.11
Boiler 23	IAA	0.02	0.10	0.10	0.01	1.31	0.07	1.10	0.02	0.02
Emergency Diesel Generator 024	IAA	0.13	0.08	0.08	0.76	2.45	0.13	1.04	2.08E-03	1.03E-03
Natural gas heaters and boiler	IAA	0.20	0.79	0.79	0.06	10.34	0.57	8.68	0.20	0.19
Diesel Emergency Generators 025 and 026	IAA	0.47	0.47	0.47	0.44	6.63	0.54	1.43	5.80E-03	1.77E-03
IMCCEP Boiler # 1 (worst case)	JMS	6.05	14.07	14.07	86.22	83.20	6.66	85.90	2.43	2.18
IMCCEP Boiler # 2 (worst case)	JMS									
IMCCEP Boiler # 3 (worst case)	JMS									
IMCCEP Boiler # 4 (worst case)	JMS									
Generators < 600 hp	JMS	1.30	1.30	1.30	1.22	18.52	1.51	3.99	1.63E-02	4.96E-03
Generators > 600 hp	JMS	0.79	0.45	0.45	2.74	27.09	0.80	6.21	1.24E-02	6.13E-03
Ablative Coating Operation	AAR	5.25	5.25	5.25	0.00	0.00	25.00	0.00	7.56	**5.56**
Natural Gas-Fired AMU Heat & Cure Oven	AAR	0.02	0.08	0.08	0.01	1.10	0.06	0.92	0.02	0.02
Surface Coating P-2	AAR	0.92	0.92	0.92	0.00	0.00	25.00	0.00	0.84	0.44
NG Make-Up Air Heating Unit B-1	AAR	0.30	1.20	1.20	0.09	15.77	0.87	13.25	0.30	0.28
Surface Coating (Emission Units 013, 017, 018)	AAR	21.61	21.61	21.61	0.00	0.00	94.77	0.00	3.47	0.95
Emission Units from Chautauqua	CHA	0.0	0.0	0.0	0.0	0.0	negligible	0.0	negligible	negligible
ASIG: Generators > 600 hp	ASIG	0.28	0.13	0.13	0.76	4.77	0.22	5.87	3.46E-03	1.71E-03
ASIG: Tanks	ASIG	0.00	0.00	0.00	0.00	0.00	0.70	0.00	0.00	0.00
Totals:		**40.47**	**48.60**	**48.60**	**99.90**	**228.55**	**162.13**	**180.78**	**15.87**	**NA**

Appendix A to the Technical Support Document - Emission Calculations
Source Wide Potential to Emit

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek
Date: December 10, 2014

Summary of Potential to Emit										
		Potential To Emit (ton/yr)							HAP	
Process / Emission Unit	**Location**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NOx**	**VOC**	**CO**	**Total**	**Single**
Emergency Diesel Generator EU-13	IAA	0.49	0.22	0.22	1.33	8.36	0.39	10.29	6.06E-03	2.99E-03
Emergency Diesel Generator EU-14	IAA	0.49	0.22	0.22	1.33	8.36	0.39	10.29	6.06E-03	2.99E-03
Tank A	IAA	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00
Emergency Diesel Generator EU-15	IAA	0.19	0.08	0.08	0.51	3.19	0.15	3.93	2.31E-03	1.14E-03
Emergency Diesel Generator EU-16	IAA	0.33	0.15	0.15	0.91	5.68	0.26	6.99	4.12E-03	2.03E-03
Emergency Diesel Generator EU-18	IAA	0.34	0.15	0.15	0.93	5.81	0.27	7.14	4.21E-03	2.08E-03
Emergency Diesel Generator EU-21	IAA	0.07	0.07	0.07	0.07	0.51	0.08	0.22	8.93E-04	2.75E-04
Emergency Diesel Generator EU-500	IAA	0.18	0.08	0.08	0.50	3.16	0.15	3.88	2.29E-03	1.13E-03
Degreasing	IAA	0.14	0.14	0.14	0.00	0.00	2.38	0.00	0.86	0.62
Generators < 600 hp	IAA	0.30	0.30	0.30	0.28	4.24	0.00	0.91	3.73E-03	8.98E-04
Generators > 600 hp, Elec. Vault	IAA	0.13	0.08	0.08	0.46	4.50	0.13	1.03	2.07E-03	1.02E-03
Generators > 600 hp, Eagle Hub	IAA	0.35	0.20	0.20	1.23	7.70	0.36	2.78	5.58E-03	2.75E-03
Boilers < 100 mmBtu/hr	IAA	0.11	0.45	0.45	0.04	5.86	0.32	4.92	0.11	0.11
Boiler 23	IAA	0.02	0.10	0.10	0.01	1.31	0.07	1.10	0.02	0.02
Emergency Diesel Generator 024	IAA	0.13	0.08	0.08	0.76	2.45	0.13	1.04	2.08E-03	1.03E-03
Natural gas heaters and boiler	IAA	0.20	0.79	0.79	0.06	10.34	0.57	8.68	0.20	0.19
Diesel Emergency Generators 025 and 026	IAA	0.47	0.47	0.47	0.44	6.63	0.54	1.43	5.80E-03	1.77E-03
IMCCEP Boiler # 1 (worst case)	JMS	0.79	1.31	1.31	15.73	7.91	0.30	4.54	0.13	0.10
IMCCEP Boiler # 2 (worst case)	JMS	1.58	2.61	2.61	31.46	15.82	0.60	9.09	0.26	0.19
IMCCEP Boiler # 3 (worst case)	JMS	7.66	12.64	12.64	152.30	99.54	2.88	44.01	1.24	0.94
IMCCEP Boiler # 4 (worst case)	JMS	7.66	12.64	12.64	152.30	99.54	2.88	44.01	1.24	0.94
Generators < 600 hp	JMS	1.30	1.30	1.30	1.22	18.52	1.51	3.99	1.63E-02	4.96E-03
Generators > 600 hp	JMS	0.79	0.45	0.45	2.74	27.09	0.80	6.21	1.24E-02	6.13E-03
Ablative Coating Operation	AAR	5.25	5.25	5.25	0.00	0.00	26.37	0.00	7.56	**5.56**
Natural Gas-Fired AMU Heat & Cure Oven	AAR	0.02	0.08	0.08	0.01	1.10	0.06	0.92	0.02	0.02
Surface Coating P-2	AAR	0.92	0.92	0.92	0.00	0.00	25.00	0.00	0.84	0.44
NG Make-Up Air Heating Unit B-1	AAR	0.30	1.20	1.20	0.09	15.77	0.87	13.25	0.30	0.28
Surface Coating (Emission Units 013, 017, 018)	AAR	57.93	57.93	57.93	0.00	0.00	94.77	0.00	3.47	0.95
Emission Units from Chautauqua	CHA	0.0	0.0	0.0	0.0	0.0	negligible	0.0	negligible	negligible
ASIG: Generators > 600 hp	ASIG	0.28	0.13	0.13	0.76	4.77	0.22	5.87	3.46E-03	1.71E-03
ASIG: Tanks	ASIG	0.0	0.0	0.0	0.0	0.0	0.70	0.0	0.00E+00	0
Totals:		**88.43**	**100.05**	**100.05**	**365.47**	**368.16**	**163.51**	**196.53**	**16.31**	**NA**
									1.23	

Appendix A to the Technical Support Document - Emission Calculations
Indianapolis Airport Authority - Generator 13

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	2200.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	1,100,000
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC*	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.49	0.22	0.22	1.33	8.36	0.39	10.29

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). Assume PM2.5 = PM10. VOC = Table 3.4-1.

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.99E-03	1.08E-03	7.43E-04	3.04E-04	9.70E-05	3.03E-05	8.16E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	6.06E-03

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generator 14

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	2200.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	1,100,000
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.49	0.22	0.22	1.33	8.36	0.39	10.29

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM2.5 = PM10, VOC Table 3.4-1

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.99E-03	1.08E-03	7.43E-04	3.04E-04	9.70E-05	3.03E-05	8.16E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	6.06E-03

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA - Tank A

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Storage Tanks ID	Product Stored	Type of Tank	Tank Volumes	Tank Volumes (gal)	Date Installed
Stand A	Jet Fuel	Internal Floating Roof	113,825	840,000	1978
Stand B-East	(Removed under 35016)				
Stand B-West					

Storage Tanks ID	Tank Volumes (gal)	Turnovers	Throughput (Gal)	Working Loss	Working Loss Lbs/1000 gal	Breathing Loss
Stand A	840,000	57.14	40000000	204	0.0051	512
Stand B-East	(Removed under 35016)					
Stand B-West						
			40000000	204	0.0051	512

Maximum Product throughput (gal/yr)	40,000,000
Maximum working loss (lbs/1000 gal)	0.0051
Max emissions from Working Loss (lbs/yr)	204
Breathing Loss for Product, (lbs/yr)	512.18
Total Emissions from Product (tons/yr)	0.36

The US EPA TANKS program was used to estimate the breathing and working losses from each tank

For each Tank, the withdrawal loss was then divided by the throughput that was placed in the TANKS4 program to determine the worst case unit working loss (lbs/1000 gallons)

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generator 15

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	840
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	420,000
Sulfur Content (S) of Fuel (% by weight)	0.3

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.19	0.08	0.08	0.51	3.19	0.15	3.93

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM2.5 = PM10, VOC = Table 3.4-1.

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Form.	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.14E-03	4.13E-04	2.84E-04	1.16E-04	3.70E-05	1.16E-05	3.12E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**2.31E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Form. = formaldehyde

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generator 16

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	1495
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	747,500
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.33	0.15	0.15	0.91	5.68	0.26	6.99

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM2.5=PM10, VOC = Table 3.4-1.

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.03E-03	7.35E-04	5.05E-04	2.06E-04	6.59E-05	2.06E-05	5.55E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**4.12E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generator 18

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	1528
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	764,000
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.34	0.15	0.15	0.93	5.81	0.27	7.14

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM2.5=PM10, VOC = Table 3.4-1.

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.08E-03	7.51E-04	5.16E-04	2.11E-04	6.74E-05	2.11E-05	5.67E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**4.21E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generator 21

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	133
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	66,500
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM	PM10*	PM2.5*	SO2	NOx**	VOC	CO
Emission Factor in lb/hp-hr	2.20E-03	2.20E-03	2.20E-03	2.05E-03	1.52E-02	2.51E-03	6.68E-03
Potential Emission in tons/yr	0.07	0.07	0.07	0.07	0.51	0.08	0.22

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1). PM=PM10=PM2.5. VOC and CO Table 3.3-1.

**NOx emission factor was taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	2.17E-04	9.51E-05	6.65E-05	2.75E-04	1.79E-04	2.15E-05	3.92E-05

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-2).

Potential Emission of Total HAPs (tons/yr)	**8.93E-04**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 , 3.3-2, 3.3-3

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
Emergency Standby Generator 500 Hours

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	831
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	415,500
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.18	0.08	0.08	0.50	3.16	0.15	3.88

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM2.5 = PM10, VOC = Table 3.4-1

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII Table 1

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.13E-03	4.09E-04	2.81E-04	1.15E-04	3.66E-05	1.15E-05	3.08E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**2.29E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Surface Coating & Degreasing & Storage Tanks

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek
Date: December 10, 2014

Material	Density (Lb/Gal)	Weight % Volatile (H20 & Organics)	Weight % Water	Weight % Organics	Volume % Water	Volume % Non-Volatiles (solids)	Gal of Mat. (gal/unit)	Maximum (unit/hour)	Pounds VOC per gallon of coating less water	Pounds VOC per gallon of coating	Potential VOC pounds per hour	Potential VOC pounds per day	Potential VOC tons per year	PM/PM10 (ton/yr)	lb VOC/gal solids	Transfer Efficiency
PPG DBU-1 Deltron Basecoat	8.6	66.00%	0.0%	66.0%	0.0%	47.00%	0.03750	1.000	5.64	5.64	0.21	5.08	0.93	0.14	12.01	70%
PPG DRR1170 Reducer	7.1	96.44%	0.0%	96.4%	0.0%	2.75%	0.01250	1.000	6.88	6.88	0.09	2.06	0.38	0.00	250.04	NA
											0.30	**7.14**	**1.3**	**0.14**		

Worst case coating/promotor, reducer, remover consumption, gallons per day **1.20**

METHODOLOGY

Pounds of VOC per Gallon Coating less Water = (Density (lb/gal) * Weight % Organics) / (1-Volume % water)
Pounds of VOC per Gallon Coating = (Density (lb/gal) * Weight % Organics)
Potential VOC Pounds per Hour = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr)
Potential VOC Pounds per Day = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (24 hr/day)
Potential VOC Tons per Year = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (8760 hr/yr) * (1 ton/2000 lbs)
PM10 emission is assumed equal to PM
PM/PM10 Potential Tons per Year = (units/hour) * (gal/unit) * (lbs/gal) * (1- Weight % Volatiles) * (1-Transfer efficiency) *(8760 hrs/yr) *(1 ton/2000 lbs)
Pounds VOC per Gallon of Solids = (Density (lbs/gal) * Weight % organics) / (Volume % solids)
Total = Worst Coating + Sum of all solvents used

Degreasing
2 tanks x 145 gallons maximum usage each/12 months x 7.36 lbs VOC/gallon x ton/2000 pounds **1.07** tons VOC/yr

Storage Tanks
IAA submitted with application that small storage tanks at IAA have the potential to emit **0.01** tons VOC/yr

Hazardous Air Pollutants (HAPs)

Material	Density (Lb/Gal)	Gallons of Material (gal/unit)	Maximum Usage (unit/hour)	Weight % Xylene	Weight % Toluene	Weight % Ethyl Benzene	Xylene Emissions (ton/yr)	Toluene Emissions (ton/yr)	Ethyl Benzene Emissions (ton/yr)	Combined HAP Emissions (ton/yr)
PPG DBU-1 Deltron Basecoat	8.6	0.03750	1.0	10.00%	40.00%	5.00%	0.14	0.57	0.07	0.78
PPG DRR1170 Reducer	7.1	0.012500	1.0	7.00%	13.00%	1.00%	0.03	0.05	0.004	0.08
Total State Potential Emissions							**0.17**	**0.62**	**0.07**	**0.86**

METHODOLOGY

HAPS emission rate (tons/yr) = Density (lb/gal) * Gal of Material (gal/unit) * Maximum (unit/hr) * Weight % HAP * 8760 hrs/yr * 1 ton/2000 lbs

Appendix A to the Technical Support Document - Emission Calculations
IAA Emergency Generators
Diesel Fuel < 600 HP

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Unit Location	horsepower	
Main Terminal -LAN Room		(226 hp removed under 35016)
South Tug Guard Shack	70	
Gate 10 Guard Shack	70	
Midfield Road Access Gate	70	
Main Terminal -Main Concourse		(535 hp removed under 35016)
Airport Fire Station		(300 hp removed under 31891)
Airfield Maintenance Bldg.	340	
Midfield Program Office		(600 hp removed under 31891)
sum total	550	hp
	3.850	MMBtu/hr

max heat input MMBtu / hr
3.9

	PM	PM10/2.5	SOx	NOx	VOC	CO
Emission Factor lbs / MMBtu	0.31	0.31	0.29	4.41	2.51E-03	0.95
Potential Emissions lbs / hr	1.19	1.19	1.12	16.98	0.01	3.66
tons / yr @ 500 hrs / yr	0.30	0.30	0.28	4.24	0.00	0.91

Methodology

AP-42 App. A Conversion Factor:	7000 Btu/horsepower hr
Emission Factor (lbs / MMBtu):	from AP-42 Table 3.3-1 & 3.3-2 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines
Diesel fuel Btu:	137000 Btu/gal (per AP-42 Appendix A)
Potential Emissions (lbs / hr):	emfac x heat input
Potential Emissions (tons / yr):	lbs / hr emissions x 500 operating hrs / yr x ton / 2000 lbs

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/MMBtu	9.33E-04	4.09E-04	2.85E-04	3.91E-05	1.18E-03	7.67E-04	9.25E-05	1.68E-04
Potential Emission in tons/yr	8.98E-04	3.94E-04	2.74E-04	3.76E-05	1.14E-03	7.38E-04	8.90E-05	1.62E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	3.73E-03

Methodology

Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Airfield Maintenance Electrical Vault Generator Cummins Model 1010 Straight 6

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: **David Matousek**

Date: **December 10, 2014**

Output Horsepower Rating (hp)	750.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	375,000
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM*	PM10*	PM2.5*	SO2*	NOx**	VOC*	CO*
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	2.40E-02 **see below	7.05E-04	5.50E-03
Potential Emission in tons/yr	0.13	0.08	0.08	0.46	4.50	0.13	1.03

*Emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-1). PM2.5=PM10

**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.02E-03	3.69E-04	2.53E-04	1.04E-04	3.31E-05	1.03E-05	2.78E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**2.07E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Eagle Hub Emergency Generator

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	2,025.00
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	1,012,500
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM*	PM10*	PM2.5*	SO2*	NOx**	VOC*	CO*
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02 **see below	7.05E-04	5.50E-03
Potential Emission in tons/yr	0.35	0.20	0.20	1.23	7.70	0.36	2.78

*Emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-1). PM2.5=PM10

**NOx emission factor: Provided by Permittee

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	2.75E-03	9.96E-04	6.84E-04	2.80E-04	8.93E-05	2.79E-05	7.51E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-3).

Potential Emission of Total HAPs (tons/yr)	**5.58E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Misc. Natural Gas Combustion Only
MMBTU/HR <100

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: **David Matousek**

Date: **December 10, 2014**

	Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr	
EU-04	8.998	78.8	
EU-05	2.247	19.7	
EU-19	1.00	8.8	
EU-20	1.00	8.8	
EU-22	0.125	1.1	
(2) 2009 Boilers		0.0	2x 0.5 MMBtu boilers removed under 31891
Total	13.370	117.1	

		Pollutant						
		PM*	PM10*	PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF		1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	EU-04	0.07	0.30	0.30	0.02	3.94	0.22	3.31
	EU-05	0.02	0.07	0.07	0.01	0.98	0.05	0.83
	EU-19	0.01	0.03	0.03	2.63E-03	0.44	0.02	0.37
	EU-20	0.01	0.03	0.03	2.63E-03	0.44	0.02	0.37
	EU-22	1.04E-03	4.16E-03	4.16E-03	3.29E-04	0.05	3.01E-03	0.05
	(2) 2009 Boilers	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total:	**0.11**	**0.45**	**0.45**	**0.04**	**5.86**	**0.32**	**4.92**

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu MMCF = 1,000,000 Cubic Feet of Gas

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

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

		HAPs - Organics				
		Benzene	zene	de	Hexane	Toluene
Emission Factor in lb/MMcf		2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	Total	1.2E-04	7.0E-05	4.4E-03	1.1E-01	2.0E-04
		HAPs - Metals				
		Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf		5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	Total	2.9E-05	6.4E-05	8.2E-05	2.2E-05	1.2E-04

Potential Emission of Total HAPs (tons/yr)	**1.1E-01**

The five highest organic and metal HAPs emission factors are provided above.

Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A to the Technical Support Document - Emission Calculations
IAA Boiler No. 23
Utility Boiler

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: **David Matousek**

Date: **December 10, 2014**

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
3.0	26.28

	Pollutant					
	PM*	PM10/2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.02	0.10	0.01	1.31	0.07	1.10

*PM emission factor is filterable PM only. PM10 emission factor is condensable and filterable PM10 combined.

**Emission Factors for NOx: Uncontrolled = 280 (pre-NSPS) or 190 (post-NSPS), Low NOx Burner = 140, Flue gas recirculation = 100 (See Table 1.4-1)

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Emission Factors from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, and 1.4-3, SCC #1-01-006-01, 1-01-006-04
(AP-42 Supplement D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.10E-03	1.20E-03	7.50E-02	1.80E+00	3.40E-03
Potential Emission in tons/yr	2.8E-05	1.6E-05	9.9E-04	2.4E-02	4.5E-05

	HAPs - Metals				
	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.00E-04	1.10E-03	1.40E-03	3.80E-04	2.10E-03
Potential Emission in tons/yr	6.6E-06	1.4E-05	1.8E-05	5.0E-06	2.8E-05

Total HAPs **2.5E-02**

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A to the Technical Support Document - Emission Calculations
IAA Large Reciprocating Internal Combustion Engines - Diesel Fuel - EU024
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	755.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	377,500
Sulfur Content (S) of Fuel (% by weight)	0.500

	Pollutant						
	PM*	PM10*	PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	4.05E-03 *(.00809S)*	1.30E-02 **see below	7.05E-04	5.50E-03
Potential Emission in tons/yr	0.13	0.08	0.08	0.76	2.45	0.13	1.04

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.4-2). PM10=PM2.5

**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.03E-03	3.71E-04	2.55E-04	1.04E-04	3.33E-05	1.04E-05	2.80E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.08E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Methodology

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
IAA Natural Gas Combustion Only < 100 MMBtu/hr

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Unit Location	MMBtu/hr
International Arrivals	2.25
12 Heaters Bldg. 100	10.56
10 Heaters Bldg. 105	2.50
Ten Heaters Bldg. 53	2.00
Eleven Heaters Bldg. 54	0.66
Eagle Hub	2.72
Four Ambi-Rad Htrs FH2	0.60
Five Ambi-Rad Htrs AMB5	0.75
Three Sterling Htrs AMB6	0.30
Two Heaters FH1	0.50
Six RG Htrs FH1	0.48
One Carrier roof top FH1	0.08
One Heater AMB2	0.13
Two Boilers	0.08
sum total	23.605

Heat Input Capacity MMBtu/hr	HHV MMBtu / MMCF	Potential Throughput MMCF/yr
23.605	1000	206.78

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.20	0.79	0.79	0.06	10.34	0.57	8.68

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.

PM2.5 emission factor is filterable and condensable PM2.5 combined.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu. MMCF = 1,000,000 Cubic Feet of Gas

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

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	
Emission Factor in lb/MMCF	2.10E-03	1.20E-03	7.50E-02	1.80E+00	3.40E-03	
Potential Emission in tons/yr	2.2E-04	1.2E-04	7.8E-03	1.9E-01	3.5E-04	
	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	
Emission Factor in lb/MMCF	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	5.2E-05	1.1E-04	1.4E-04	3.9E-05	2.2E-04	0.20 Total HAP

The five highest organic and metal HAPs emission factors are provided above.

Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A to the Technical Support Document - Emission Calculations
IAA Reciprocating Internal Combustion Engines - Generators 025 and 026
Output Rating (<=600 HP) Maximum Input Rate (<=4.2 MMBtu/hr)

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: **David Matousek**

Date: **December 10, 2014**

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	380	Emergency Generator 025
Output Horsepower Rating (hp)	476	Emergency Generator 026
Total (hp)	**856**	

Maximum Hours Operated per Year	500	380 hp located at Building 60 and 476 hp located at Fire House 2
Potential Throughput (hp-hr/yr)	428,000	

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0.0025	0.0067
Potential Emission in tons/yr	0.47	0.47	0.47	0.44	6.63	0.54	1.43

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	1.40E-03	6.13E-04	4.27E-04	5.86E-05	1.77E-03	1.15E-03	1.39E-04	2.52E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**5.80E-03**

Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #1 at Johnson Melloh Solutions - IMC Central Energy Plant

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Maximum Heat Input Capacity	12.6	MMBtu/hr	or	110,376	MMBtu/yr	
Heat Content Fuel Oil	139.50	MMBtu/kgal				
Heat Content Natural Gas	1,020.00	MMBtu/MMCF				
Max. Fuel Oil Usage (Current Permit S Content)	791.23	kgal/yr	at	2,800	ppm S	0.28 % S
Maximum Natural Gas Usage	108.21	MMCF/yr				

Potential to Emit

	Emission Factor (Natural Gas / Fuel Oil)	Throughput	PTE (TPY)	Worst Case PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	108.21 MMCF/yr	0.10	0.79	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	2 lb/kgal	791.23 kgal/yr	0.79		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
PM_{10} / Direct $PM_{2.5}$	7.6 lb/MMCF	108.21 MMCF/yr	0.41	1.31	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	3.3 lb/kgal	791.23 kgal/yr	1.31		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 1.3-2
SO_2	0.6 lb/MMCF	108.21 MMCF/yr	0.03	15.73	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	39.76 lb/kgal	791.23 kgal/yr	15.73		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 142S
VOC	5.5 lb/MMCF	108.21 MMCF/yr	0.30	0.30	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	0.252 lb/kgal	791.23 kgal/yr	0.10		AP-42, Ch. 1.3, 5/2010, Table 1.3-3
CO	84 lb/MMCF	108.21 MMCF/yr	4.54	4.54	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	5 lb/kgal	791.23 kgal/yr	1.98		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
NO_x	100 lb/MMCF	108.21 MMCF/yr	5.41	7.91	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	20 lb/kgal	791.23 kgal/yr	7.91		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
CO_2	53.06 kg/MMBtu	110,376 MMBtu/yr	6,455.68	9,149.39	40 CFR 98, Subpart C, Table C-1
	75.20 kg/MMBtu	110,376 MMBtu/yr	9,149.39		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03 kg/MMBtu	110,376 MMBtu/yr	0.12	0.37	40 CFR 98, Subpart C, Table C-2
	3.00E-03 kg/MMBtu	110,376 MMBtu/yr	0.37		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04 kg/MMBtu	110,376 MMBtu/yr	0.01	0.07	40 CFR 98, Subpart C, Table C-2
	6.00E-04 kg/MMBtu	110,376 MMBtu/yr	0.07		40 CFR 98, Subpart C, Table C-2
CO_2e				9,179.50	Calculated

Methodology:

1) Throughput (MMCF/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/MMCF)
2) Throughput (kgal/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/kgal)
3) PTE (TPY) = Emission Factor (lb/MMCF) x Usage (MMCF/yr) x 1 ton/2,000 lb
4) PTE (TPY) = Emission Factor (lb/kgal) x Usage (kgal/yr) x 1 ton/2,000 lb
5) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Usage (MMBtu/yr) x 1 ton/2,000 lb
6) CO_2e (TPY) = CO_2 Emissions + (CH_4 Emissions x Global Warming Potential (25)) + (N_2O Emissions x (Global Warming Potential 298))
7) Worst Case PTE (TPY) = Highest Potential Emission Rate (TPY) of Fuel Oil Combustion and Natural Gas Combustion for each pollutant.

(Continued on Next Page)

Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #1 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	None	None	None		No emission factor
1,1,1-Trichloroethane	2.36E-04 lb/kgal	791.23 kgal/yr	9.34E-05	9.34E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	108.21 MMCF/yr	1.30E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
2-methylnaphthalene	None	None	None	1.30E-06	No emission factor
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
3-methylchloranthrene	None	None	None	9.74E-08	No emission factor
	1.60E-05 lb/MMCF	108.21 MMCF/yr	8.66E-07		No emission factor
7,12-dimethylbenz(a)anthracene	None	None	None	8.66E-07	No emission factor
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthene	2.11E-05 lb/kgal	791.23 kgal/yr	8.35E-06	8.35E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthylene	2.53E-07 lb/kgal	791.23 kgal/yr	1.00E-07	1.00E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-06 lb/MMCF	108.21 MMCF/yr	1.30E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Anthracene	1.22E-06 lb/kgal	791.23 kgal/yr	4.83E-07	4.83E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.00E-04 lb/MMCF	108.21 MMCF/yr	1.08E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Arsenic	4.00E-06 lb/MMBtu	110,376 MMBtu/yr	2.21E-04	2.21E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benz(a)anthracene	4.01E-06 lb/kgal	791.23 kgal/yr	1.59E-06	1.59E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	108.21 MMCF/yr	1.14E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzene	2.14E-04 lb/kgal	791.23 kgal/yr	8.47E-05	1.14E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	108.21 MMCF/yr	6.49E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(a)pyrene	None	None	None	6.49E-08	No emission factor
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(b)fluoranthene	None	None	None	9.74E-08	No emission factor
	1.20E-06 lb/MMCF	108.21 MMCF/yr	6.49E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(g,h,i)perylene	2.26E-06 lb/kgal	791.23 kgal/yr	8.94E-07	8.94E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(k)fluoranthene	None	None	None	9.74E-08	No emission factor
	1.20E-05 lb/MMCF	108.21 MMCF/yr	6.49E-07		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Beryllium	3.00E-06 lb/MMBtu	110,376 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.10E-03 lb/MMCF	108.21 MMCF/yr	5.95E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Cadmium	3.00E-06 lb/MMBtu	110,376 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.40E-03 lb/MMCF	108.21 MMCF/yr	7.57E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Chromium	3.00E-06 lb/MMBtu	110,376 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Chrysene	2.38E-06 lb/kgal	791.23 kgal/yr	9.42E-07	9.42E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	108.21 MMCF/yr	6.49E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dibenzo(a,h)anthracene	1.67E-06 lb/kgal	791.23 kgal/yr	6.61E-07	6.61E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-03 lb/MMCF	108.21 MMCF/yr	6.49E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dichlorobenzene	None	None	None	6.49E-05	No emission factor
	None	None	None		No emission factor
Ethylbenzene	6.36E-05 lb/kgal	791.23 kgal/yr	2.52E-05	2.52E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

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Potential to Emit - Boiler #1 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	3.00E-06 lb/MMCF	108.21 MMCF/yr	1.62E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluoranthene	4.84E-06 lb/kgal	791.23 kgal/yr	1.91E-06	1.91E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.80E-06 lb/MMCF	108.21 MMCF/yr	1.51E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluorene	4.47E-06 lb/kgal	791.23 kgal/yr	1.77E-06	1.77E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	7.50E-02 lb/MMCF	108.21 MMCF/yr	4.06E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Formaldehyde	0.061 lb/kgal	791.23 kgal/yr	2.41E-02	2.41E-02	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	1.8 lb/MMCF	108.21 MMCF/yr	0.10		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Hexane	None	None	None	0.10	No emission factor
	1.80E-06 lb/MMCF	108.21 MMCF/yr	9.74E-08		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Indo(1,2,3-cd)pyrene	2.14E-06 lb/kgal	791.23 kgal/yr	8.47E-07	8.47E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Lead	9.00E-06 lb/MMBtu	110,376 MMBtu/yr	4.97E-04	4.97E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.80E-04 lb/MMCF	108.21 MMCF/yr	2.06E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Manganese	6.00E-06 lb/MMBtu	110,376 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	2.60E-04 lb/MMCF	108.21 MMCF/yr	1.41E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Mercury	3.00E-06 lb/MMBtu	110,376 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	6.10E-04 lb/MMCF	108.21 MMCF/yr	3.30E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Naphthalene	1.13E-03 lb/kgal	791.23 kgal/yr	4.47E-04	4.47E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	108.21 MMCF/yr	1.14E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Nickel	3.00E-06 lb/MMBtu	110,376 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.70E-05 lb/MMCF	108.21 MMCF/yr	9.20E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Phenanthrene	1.05E-05 lb/kgal	791.23 kgal/yr	4.15E-06	4.15E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Polycyclic Organic Matter	0.0033 lb/kgal	791.23 kgal/yr	1.31E-03	1.31E-03	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	5.00E-06 lb/MMCF	108.21 MMCF/yr	2.71E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Pyrene	4.25E-06 lb/kgal	791.23 kgal/yr	1.68E-06	1.68E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	108.21 MMCF/yr	1.30E-06		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Selenium	1.50E-06 lb/MMBtu	110,376 MMBtu/yr	8.28E-05	8.28E-05	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.40E-03 lb/MMCF	108.21 MMCF/yr	1.84E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Toluene	6.30E-03 lb/kgal	791.23 kgal/yr	2.49E-03	2.49E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Xylene	1.09E-04 lb/kgal	791.23 kgal/yr	4.31E-05	4.31E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

Worst Case HAP at PTE	**0.10 TPY**	**(Hexane)**
Total HAP at PTE	**0.13 TPY**	

Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #2 at Johnson Melloh Solutions - IMC Central Energy Plant

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Maximum Heat Input Capacity	25.2	MMBtu/hr	or	220,752	MMBtu/yr	
Heat Content Fuel Oil	139.50	MMBtu/kgal				
Heat Content Natural Gas	1,020.00	MMBtu/MMCF				
Max. Fuel Oil Usage (Current Permit S Content)	1,582.45	kgal/yr	at	2,800	ppm S	0.28 % S
Maximum Natural Gas Usage	216.42	MMCF/yr				

Potential to Emit

	Emission Factor (Natural Gas / Fuel Oil)	Throughput	PTE (TPY)	Worst Case PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	216.42 MMCF/yr	0.21	1.58	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	2 lb/kgal	1,582.45 kgal/yr	1.58		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
PM_{10} / Direct $PM_{2.5}$	7.6 lb/MMCF	216.42 MMCF/yr	0.82	2.61	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	3.3 lb/kgal	1,582.45 kgal/yr	2.61		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 1.3-2
SO_2	0.6 lb/MMCF	216.42 MMCF/yr	0.06	31.46	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	39.76 lb/kgal	1,582.45 kgal/yr	31.46		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 142S
VOC	5.5 lb/MMCF	216.42 MMCF/yr	0.60	0.60	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	0.252 lb/kgal	1,582.45 kgal/yr	0.20		AP-42, Ch. 1.3, 5/2010, Table 1.3-3
CO	84 lb/MMCF	216.42 MMCF/yr	9.09	9.09	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	5 lb/kgal	1,582.45 kgal/yr	3.96		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
NO_x	100 lb/MMCF	216.42 MMCF/yr	10.82	15.82	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	20 lb/kgal	1,582.45 kgal/yr	15.82		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
CO_2	53.06 kg/MMBtu	220,752 MMBtu/yr	12,911.35	18,298.79	40 CFR 98, Subpart C, Table C-1
	75.20 kg/MMBtu	220,752 MMBtu/yr	18,298.79		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03 kg/MMBtu	220,752 MMBtu/yr	0.24	0.73	40 CFR 98, Subpart C, Table C-2
	3.00E-03 kg/MMBtu	220,752 MMBtu/yr	0.73		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04 kg/MMBtu	220,752 MMBtu/yr	0.02	0.15	40 CFR 98, Subpart C, Table C-2
	6.00E-04 kg/MMBtu	220,752 MMBtu/yr	0.15		40 CFR 98, Subpart C, Table C-2
CO_2e				18,361.74	Calculated

Methodology:
1) Throughput (MMCF/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/MMCF)
2) Throughput (kgal/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/kgal)
3) PTE (TPY) = Emission Factor (lb/MMCF) x Usage (MMCF/yr) x 1 ton/2,000 lb
4) PTE (TPY) = Emission Factor (lb/kgal) x Usage (kgal/yr) x 1 ton/2,000 lb
5) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Usage (MMBtu/yr) x 1 ton/2,000 lb
6) CO_2e (TPY) = CO_2 Emissions + (CH_4 Emissions x Global Warming Potential (25)) + (N_2O Emissions x (Global Warming Potential 298))
7) Worst Case PTE (TPY) = Highest Potential Emission Rate (TPY) of Fuel Oil Combustion and Natural Gas Combustion for each pollutant.

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Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #2 at Johnson Melloh Solutions - IMC Central Energy Plant

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	Potential to Emit				
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	None	None	None		No emission factor
1,1,1-Trichloroethane	2.36E-04 lb/kgal	1,582.45 kgal/yr	1.87E-04	1.87E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	216.42 MMCF/yr	2.60E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
2-methylnaphthalene	None	None	None	2.60E-06	No emission factor
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
3-methylchloranthrene	None	None	None	1.95E-07	No emission factor
	1.60E-05 lb/MMCF	216.42 MMCF/yr	1.73E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
7,12-dimethylbenz(a)anthracene	None	None	None	1.73E-06	No emission factor
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthene	2.11E-05 lb/kgal	1,582.45 kgal/yr	1.67E-05	1.67E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthylene	2.53E-07 lb/kgal	1,582.45 kgal/yr	2.00E-07	2.00E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-06 lb/MMCF	216.42 MMCF/yr	2.60E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Anthracene	1.22E-06 lb/kgal	1,582.45 kgal/yr	9.65E-07	9.65E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.00E-04 lb/MMCF	216.42 MMCF/yr	2.16E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Arsenic	4.00E-06 lb/MMBtu	220,752 MMBtu/yr	4.42E-04	4.42E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benz(a)anthracene	4.01E-06 lb/kgal	1,582.45 kgal/yr	3.17E-06	3.17E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	216.42 MMCF/yr	2.27E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzene	2.14E-04 lb/kgal	1,582.45 kgal/yr	1.69E-04	2.27E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	216.42 MMCF/yr	1.30E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(a)pyrene	None	None	None	1.30E-07	No emission factor
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(b)fluoranthene	None	None	None	1.95E-07	No emission factor
	1.20E-06 lb/MMCF	216.42 MMCF/yr	1.30E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(g,h,i)perylene	2.26E-06 lb/kgal	1,582.45 kgal/yr	1.79E-06	1.79E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(k)fluoranthene	None	None	None	1.95E-07	No emission factor
	1.20E-05 lb/MMCF	216.42 MMCF/yr	1.30E-06		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Beryllium	3.00E-06 lb/MMBtu	220,752 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.10E-03 lb/MMCF	216.42 MMCF/yr	1.19E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Cadmium	3.00E-06 lb/MMBtu	220,752 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.40E-03 lb/MMCF	216.42 MMCF/yr	1.51E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Chromium	3.00E-06 lb/MMBtu	220,752 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Chrysene	2.38E-06 lb/kgal	1,582.45 kgal/yr	1.88E-06	1.88E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	216.42 MMCF/yr	1.30E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dibenzo(a,h)anthracene	1.67E-06 lb/kgal	1,582.45 kgal/yr	1.32E-06	1.32E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-03 lb/MMCF	216.42 MMCF/yr	1.30E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dichlorobenzene	None	None	None	1.30E-04	No emission factor
	None	None	None		No emission factor
Ethylbenzene	6.36E-05 lb/kgal	1,582.45 kgal/yr	5.03E-05	5.03E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

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Potential to Emit - Boiler #2 at Johnson Melloh Solutions - IMC Central Energy Plant

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Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	3.00E-06 lb/MMCF	216.42 MMCF/yr	3.25E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluoranthene	4.84E-06 lb/kgal	1,582.45 kgal/yr	3.83E-06	3.83E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.80E-06 lb/MMCF	216.42 MMCF/yr	3.03E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluorene	4.47E-06 lb/kgal	1,582.45 kgal/yr	3.54E-06	3.54E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	7.50E-02 lb/MMCF	216.42 MMCF/yr	8.12E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Formaldehyde	0.061 lb/kgal	1,582.45 kgal/yr	4.83E-02	4.83E-02	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	1.8 lb/MMCF	216.42 MMCF/yr	0.19		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Hexane	None	None	None	0.19	No emission factor
	1.80E-06 lb/MMCF	216.42 MMCF/yr	1.95E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Indo(1,2,3-cd)pyrene	2.14E-06 lb/kgal	1,582.45 kgal/yr	1.69E-06	1.69E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Lead	9.00E-06 lb/MMBtu	220,752 MMBtu/yr	9.93E-04	9.93E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.80E-04 lb/MMCF	216.42 MMCF/yr	4.11E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Manganese	6.00E-06 lb/MMBtu	220,752 MMBtu/yr	6.62E-04	6.62E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	2.60E-04 lb/MMCF	216.42 MMCF/yr	2.81E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Mercury	3.00E-06 lb/MMBtu	220,752 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	6.10E-04 lb/MMCF	216.42 MMCF/yr	6.60E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Naphthalene	1.13E-03 lb/kgal	1,582.45 kgal/yr	8.94E-04	8.94E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	216.42 MMCF/yr	2.27E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Nickel	3.00E-06 lb/MMBtu	220,752 MMBtu/yr	3.31E-04	3.31E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.70E-05 lb/MMCF	216.42 MMCF/yr	1.84E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Phenanthrene	1.05E-05 lb/kgal	1,582.45 kgal/yr	8.31E-06	8.31E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Polycyclic Organic Matter	0.0033 lb/kgal	1,582.45 kgal/yr	2.61E-03	2.61E-03	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	5.00E-06 lb/MMCF	216.42 MMCF/yr	5.41E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Pyrene	4.25E-06 lb/kgal	1,582.45 kgal/yr	3.36E-06	3.36E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	216.42 MMCF/yr	2.60E-06		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Selenium	1.50E-06 lb/MMBtu	220,752 MMBtu/yr	1.66E-04	1.66E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.40E-03 lb/MMCF	216.42 MMCF/yr	3.68E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Toluene	6.30E-03 lb/kgal	1,582.45 kgal/yr	4.98E-03	4.98E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Xylene	1.09E-04 lb/kgal	1,582.45 kgal/yr	8.62E-05	8.62E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

Worst Case HAP at PTE **0.19 TPY** **(Hexane)**

Total HAP at PTE **0.26 TPY**

Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #3 at Johnson Melloh Solutions - IMC Central Energy Plant

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Maximum Heat Input Capacity	122	MMBtu/hr	or	1,068,720	MMBtu/yr	
Heat Content Fuel Oil	139.50	MMBtu/kgal				
Heat Content Natural Gas	1,020.00	MMBtu/MMCF				
Max. Fuel Oil Usage (Current Permit S Content)	7,661.08	kgal/yr	at	2,800	ppm S	0.28 % S
Maximum Natural Gas Usage	1,047.76	MMCF/yr				

Potential to Emit

	Emission Factor (Natural Gas / Fuel Oil)	Throughput	PTE (TPY)	Worst Case PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1,047.76 MMCF/yr	1.00	7.66	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	2 lb/kgal	7,661.08 kgal/yr	7.66		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
PM_{10} / Direct $PM_{2.5}$	7.6 lb/MMCF	1,047.76 MMCF/yr	3.98	12.64	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	3.3 lb/kgal	7,661.08 kgal/yr	12.64		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 1.3-2
SO_2	0.6 lb/MMCF	1,047.76 MMCF/yr	0.31	152.30	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	39.76 lb/kgal	7,661.08 kgal/yr	152.30		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 142S
VOC	5.5 lb/MMCF	1,047.76 MMCF/yr	2.88	2.88	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	0.252 lb/kgal	7,661.08 kgal/yr	0.97		AP-42, Ch. 1.3, 5/2010, Table 1.3-3
CO	84 lb/MMCF	1,047.76 MMCF/yr	44.01	44.01	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	5 lb/kgal	7,661.08 kgal/yr	19.15		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
NO_x	190 lb/MMCF	1,047.76 MMCF/yr	99.54	99.54	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	24 lb/kgal	7,661.08 kgal/yr	91.93		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
CO_2	53.06 kg/MMBtu	1,068,720 MMBtu/yr	62,507.34	88,589.36	40 CFR 98, Subpart C, Table C-1
	75.2 kg/MMBtu	1,068,720 MMBtu/yr	88,589.36		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03 kg/MMBtu	1,068,720 MMBtu/yr	1.18	3.53	40 CFR 98, Subpart C, Table C-2
	3.00E-03 kg/MMBtu	1,068,720 MMBtu/yr	3.53		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04 kg/MMBtu	1,068,720 MMBtu/yr	0.12	0.71	40 CFR 98, Subpart C, Table C-2
	6.00E-04 kg/MMBtu	1,068,720 MMBtu/yr	0.71		40 CFR 98, Subpart C, Table C-2
CO_2e				88,889.19	Calculated

Methodology:
1) Throughput (MMCF/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/MMCF)
2) Throughput (kgal/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/kgal)
3) PTE (TPY) = Emission Factor (lb/MMCF) x Usage (MMCF/yr) x 1 ton/2,000 lb
4) PTE (TPY) = Emission Factor (lb/kgal) x Usage (kgal/yr) x 1 ton/2,000 lb
5) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Usage (MMBtu/yr) x 1 ton/2,000 lb
6) CO_2e (TPY) = CO_2 Emissions + (CH_4 Emissions x Global Warming Potential (25)) + (N_2O Emissions x (Global Warming Potential 298))
7) Worst Case PTE (TPY) = Highest Potential Emission Rate (TPY) of Fuel Oil Combustion and Natural Gas Combustion for each pollutant.

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Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #3 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	None	None	None		No emission factor
1,1,1-Trichloroethane	2.36E-04 lb/kgal	7,661.08 kgal/yr	9.04E-04	9.04E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	1,047.76 MMCF/yr	1.26E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
2-methylnaphthalene	None	None	None	1.26E-05	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
3-methylchloranthrene	None	None	None	9.43E-07	No emission factor
	1.60E-05 lb/MMCF	1,047.76 MMCF/yr	8.38E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
7,12-dimethylbenz(a)anthracene	None	None	None	8.38E-06	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthene	2.11E-05 lb/kgal	7,661.08 kgal/yr	8.08E-05	8.08E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthylene	2.53E-07 lb/kgal	7,661.08 kgal/yr	9.69E-07	9.69E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-06 lb/MMCF	1,047.76 MMCF/yr	1.26E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Anthracene	1.22E-06 lb/kgal	7,661.08 kgal/yr	4.67E-06	4.67E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.00E-04 lb/MMCF	1,047.76 MMCF/yr	1.05E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Arsenic	4.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	2.14E-03	2.14E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benz(a)anthracene	4.01E-06 lb/kgal	7,661.08 kgal/yr	1.54E-05	1.54E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	1,047.76 MMCF/yr	1.10E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzene	2.14E-04 lb/kgal	7,661.08 kgal/yr	8.20E-04	1.10E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(a)pyrene	None	None	None	6.29E-07	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(b)fluoranthene	None	None	None	9.43E-07	No emission factor
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(g,h,i)perylene	2.26E-06 lb/kgal	7,661.08 kgal/yr	8.66E-06	8.66E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(k)fluoranthene	None	None	None	9.43E-07	No emission factor
	1.20E-05 lb/MMCF	1,047.76 MMCF/yr	6.29E-06		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Beryllium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.10E-03 lb/MMCF	1,047.76 MMCF/yr	5.76E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Cadmium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.40E-03 lb/MMCF	1,047.76 MMCF/yr	7.33E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Chromium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Chrysene	2.38E-06 lb/kgal	7,661.08 kgal/yr	9.12E-06	9.12E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dibenzo(a,h)anthracene	1.67E-06 lb/kgal	7,661.08 kgal/yr	6.40E-06	6.40E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-03 lb/MMCF	1,047.76 MMCF/yr	6.29E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dichlorobenzene	None	None	None	6.29E-04	No emission factor
	None	None	None		No emission factor
Ethylbenzene	6.36E-05 lb/kgal	7,661.08 kgal/yr	2.44E-04	2.44E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

(Continued on Next Page)

Potential to Emit - Boiler #3 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	3.00E-06 lb/MMCF	1,047.76 MMCF/yr	1.57E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluoranthene	4.84E-06 lb/kgal	7,661.08 kgal/yr	1.85E-05	1.85E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.80E-06 lb/MMCF	1,047.76 MMCF/yr	1.47E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluorene	4.47E-06 lb/kgal	7,661.08 kgal/yr	1.71E-05	1.71E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	7.50E-02 lb/MMCF	1,047.76 MMCF/yr	3.93E-02		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Formaldehyde	0.061 lb/kgal	7,661.08 kgal/yr	2.34E-01	2.34E-01	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	1.8 lb/MMCF	1,047.76 MMCF/yr	0.94		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Hexane	None	None	None	0.94	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Indo(1,2,3-cd)pyrene	2.14E-06 lb/kgal	7,661.08 kgal/yr	8.20E-06	8.20E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Lead	9.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	4.81E-03	4.81E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.80E-04 lb/MMCF	1,047.76 MMCF/yr	1.99E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Manganese	6.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	3.21E-03	3.21E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	2.60E-04 lb/MMCF	1,047.76 MMCF/yr	1.36E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Mercury	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	6.10E-04 lb/MMCF	1,047.76 MMCF/yr	3.20E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Naphthalene	1.13E-03 lb/kgal	7661.08 kgal/yr	4.33E-03	4.33E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	1,047.76 MMCF/yr	1.10E-03		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Nickel	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.70E-05 lb/MMCF	1,047.76 MMCF/yr	8.91E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Phenanthrene	1.05E-05 lb/kgal	7,661.08 kgal/yr	4.02E-05	4.02E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Polycyclic Organic Matter	0.0033 lb/kgal	7,661.08 kgal/yr	1.26E-02	1.26E-02	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	5.00E-06 lb/MMCF	1,047.76 MMCF/yr	2.62E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Pyrene	4.25E-06 lb/kgal	7,661.08 kgal/yr	1.63E-05	1.63E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	1,047.76 MMCF/yr	1.26E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Selenium	1.50E-06 lb/MMBtu	1,068,720 MMBtu/yr	8.02E-04	8.02E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.40E-03 lb/MMCF	1,047.76 MMCF/yr	1.78E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Toluene	6.30E-03 lb/kgal	7,661.08 kgal/yr	2.41E-02	2.41E-02	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Xylene	1.09E-04 lb/kgal	7,661.08 kgal/yr	4.18E-04	4.18E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

Worst Case HAP at PTE **0.94 TPY** **(Hexane)**

Total HAP at PTE **1.24 TPY**

Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #4 at Johnson Melloh Solutions - IMC Central Energy Plant

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Maximum Heat Input Capacity	122	MMBtu/hr	or	1,068,720	MMBtu/yr	
Heat Content Fuel Oil	139.50	MMBtu/kgal				
Heat Content Natural Gas	1,020.00	MMBtu/MMCF				
Max. Fuel Oil Usage (Current Permit S Content)	7,661.08	kgal/yr	at	2,800	ppm S	0.28 % S
Maximum Natural Gas Usage	1,047.76	MMCF/yr				

Potential to Emit

	Emission Factor (Natural Gas / Fuel Oil)	Throughput	PTE (TPY)	Worst Case PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	1,047.76 MMCF/yr	1.00	7.66	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	2 lb/kgal	7,661.08 kgal/yr	7.66		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
PM_{10} / Direct $PM_{2.5}$	7.6 lb/MMCF	1,047.76 MMCF/yr	3.98	12.64	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	3.3 lb/kgal	7,661.08 kgal/yr	12.64		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 1.3-2
SO_2	0.6 lb/MMCF	1,047.76 MMCF/yr	0.31	152.30	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	39.76 lb/kgal	7,661.08 kgal/yr	152.30		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
VOC	5.5 lb/MMCF	1,047.76 MMCF/yr	2.88	2.88	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	0.252 lb/kgal	7,661.08 kgal/yr	0.97		AP-42, Ch. 1.3, 5/2010, Table 1.3-3
CO	84 lb/MMCF	1,047.76 MMCF/yr	44.01	44.01	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	5 lb/kgal	7,661.08 kgal/yr	19.15		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
NO_x	190 lb/MMCF	1,047.76 MMCF/yr	99.54	99.54	AP-42, Ch. 1.4, 7/1998, Table 1.4-1
	24 lb/kgal	7,661.08 kgal/yr	91.93		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
CO_2	53.06 kg/MMBtu	1,068,720 MMBtu/yr	62,507.34	88,589.36	40 CFR 98, Subpart C, Table C-1
	75.2 kg/MMBtu	1,068,720 MMBtu/yr	88,589.36		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03 kg/MMBtu	1,068,720 MMBtu/yr	1.18	3.53	40 CFR 98, Subpart C, Table C-2
	3.00E-03 kg/MMBtu	1,068,720 MMBtu/yr	3.53		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04 kg/MMBtu	1,068,720 MMBtu/yr	0.12	0.71	40 CFR 98, Subpart C, Table C-2
	6.00E-04 kg/MMBtu	1,068,720 MMBtu/yr	0.71		40 CFR 98, Subpart C, Table C-2
CO_2e				88,889.19	Calculated

Methodology:
1) Throughput (MMCF/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/MMCF)
2) Throughput (kgal/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/kgal)
3) PTE (TPY) = Emission Factor (lb/MMCF) x Usage (MMCF/yr) x 1 ton/2,000 lb
4) PTE (TPY) = Emission Factor (lb/kgal) x Usage (kgal/yr) x 1 ton/2,000 lb
5) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Usage (MMBtu/yr) x 1 ton/2,000 lb
6) CO_2e (TPY) = CO_2 Emissions + (CH_4 Emissions x Global Warming Potential (25)) + (N_2O Emissions x (Global Warming Potential 298))
7) Worst Case PTE (TPY) = Highest Potential Emission Rate (TPY) of Fuel Oil Combustion and Natural Gas Combustion for each pollutant.

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Appendix A to the Technical Support Document - Emission Calculations
Potential to Emit - Boiler #4 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

	Potential to Emit				
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	None	None	None		No emission factor
1,1,1-Trichloroethane	2.36E-04 lb/kgal	7,661.08 kgal/yr	9.04E-04	9.04E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	1,047.76 MMCF/yr	1.26E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
2-methylnaphthalene	None	None	None	1.26E-05	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
3-methylchloranthrene	None	None	None	9.43E-07	No emission factor
	1.60E-05 lb/MMCF	1,047.76 MMCF/yr	8.38E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
7,12-dimethylbenz(a)anthracene	None	None	None	8.38E-06	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthene	2.11E-05 lb/kgal	7,661.08 kgal/yr	8.08E-05	8.08E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthylene	2.53E-07 lb/kgal	7,661.08 kgal/yr	9.69E-07	9.69E-07	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-06 lb/MMCF	1,047.76 MMCF/yr	1.26E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Anthracene	1.22E-06 lb/kgal	7,661.08 kgal/yr	4.67E-06	4.67E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.00E-04 lb/MMCF	1,047.76 MMCF/yr	1.05E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Arsenic	4.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	2.14E-03	2.14E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benz(a)anthracene	4.01E-06 lb/kgal	7,661.08 kgal/yr	1.54E-05	1.54E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	1,047.76 MMCF/yr	1.10E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzene	2.14E-04 lb/kgal	7,661.08 kgal/yr	8.20E-04	1.10E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(a)pyrene	None	None	None	6.29E-07	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(b)fluoranthene	None	None	None	9.43E-07	No emission factor
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(g,h,i)perylene	2.26E-06 lb/kgal	7,661.08 kgal/yr	8.66E-06	8.66E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(k)fluoranthene	None	None	None	9.43E-07	No emission factor
	1.20E-05 lb/MMCF	1,047.76 MMCF/yr	6.29E-06		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Beryllium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.10E-03 lb/MMCF	1,047.76 MMCF/yr	5.76E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Cadmium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.40E-03 lb/MMCF	1,047.76 MMCF/yr	7.33E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Chromium	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Chrysene	2.38E-06 lb/kgal	7,661.08 kgal/yr	9.12E-06	9.12E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1,047.76 MMCF/yr	6.29E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dibenzo(a,h)anthracene	1.67E-06 lb/kgal	7,661.08 kgal/yr	6.40E-06	6.40E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-03 lb/MMCF	1,047.76 MMCF/yr	6.29E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dichlorobenzene	None	None	None	6.29E-04	No emission factor
	None	None	None		No emission factor
Ethylbenzene	6.36E-05 lb/kgal	7,661.08 kgal/yr	2.44E-04	2.44E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

(Continued on Next Page)

Potential to Emit - Boiler #4 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Throughput**	**PTE (TPY)**	**Worst Case PTE (TPY)**	**Emission Factor Source**
	3.00E-06 lb/MMCF	1,047.76 MMCF/yr	1.57E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluoranthene	4.84E-06 lb/kgal	7,661.08 kgal/yr	1.85E-05	1.85E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.80E-06 lb/MMCF	1,047.76 MMCF/yr	1.47E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Fluorene	4.47E-06 lb/kgal	7,661.08 kgal/yr	1.71E-05	1.71E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	7.50E-02 lb/MMCF	1,047.76 MMCF/yr	3.93E-02		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Formaldehyde	0.061 lb/kgal	7,661.08 kgal/yr	2.34E-01	2.34E-01	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	1.8 lb/MMCF	1,047.76 MMCF/yr	0.94		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Hexane	None	None	None	0.94	No emission factor
	1.80E-06 lb/MMCF	1,047.76 MMCF/yr	9.43E-07		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Indo(1,2,3-cd)pyrene	2.14E-06 lb/kgal	7,661.08 kgal/yr	8.20E-06	8.20E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Lead	9.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	4.81E-03	4.81E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.80E-04 lb/MMCF	1,047.76 MMCF/yr	1.99E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Manganese	6.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	3.21E-03	3.21E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	2.60E-04 lb/MMCF	1,047.76 MMCF/yr	1.36E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Mercury	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	6.10E-04 lb/MMCF	1,047.76 MMCF/yr	3.20E-04		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Naphthalene	1.13E-03 lb/kgal	7661.08 kgal/yr	4.33E-03	4.33E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	1,047.76 MMCF/yr	1.10E-03		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Nickel	3.00E-06 lb/MMBtu	1,068,720 MMBtu/yr	1.60E-03	1.60E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.70E-05 lb/MMCF	1,047.76 MMCF/yr	8.91E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Phenanthrene	1.05E-05 lb/kgal	7,661.08 kgal/yr	4.02E-05	4.02E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Polycyclic Organic Matter	0.0033 lb/kgal	7,661.08 kgal/yr	1.26E-02	1.26E-02	AP-42, Ch. 1.3, Table 1.3-8, 5/2010
	5.00E-06 lb/MMCF	1,047.76 MMCF/yr	2.62E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Pyrene	4.25E-06 lb/kgal	7,661.08 kgal/yr	1.63E-05	1.63E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	1,047.76 MMCF/yr	1.26E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Selenium	1.50E-06 lb/MMBtu	1,068,720 MMBtu/yr	8.02E-04	8.02E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	3.40E-03 lb/MMCF	1,047.76 MMCF/yr	1.78E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Toluene	6.30E-03 lb/kgal	7,661.08 kgal/yr	2.41E-02	2.41E-02	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	None	None	None		No emission factor
Xylene	1.09E-04 lb/kgal	7,661.08 kgal/yr	4.18E-04	4.18E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

Worst Case HAP at PTE **0.94 TPY** **(Hexane)**

Total HAP at PTE **1.24 TPY**

Appendix A to the Technical Support Document - Emission Calculations
Limited Potential to Emit - Boiler #1 to #4 at Johnson Melloh Solutions - IMC Central Energy Plant

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: **David Matousek**

Date: **December 10, 2014**

Combined Heat Input Capacity of Boiler #1 to #4	281.8	MMBtu/hr	or		2,468,568	MMBtu/yr
Heat Content Fuel Oil	139.50	MMBtu/kgal	at	S Wt % =	0.28	%
Heat Content Natural Gas	1,020.00	MMBtu/MMCF				

Case 1 - All Natural Gas					
Combustion on all Natural Gas	2,420.16	MMCF/yr		2,468,568	MMBtu/yr

Case 2 - Limited Fuel Oil with Makeup Natural Gas					
Make Up Natural Gas after All F.O. Used	1,830.80	MMCF/yr		1,867,413	MMBtu/yr
Limited Fuel Oil Usage (S=0.28)	4,309.356	kgal/yr	or	601,155	MMBtu/yr
				2,468,568	MMBtu/yr

Limited Potential to Emit

	Emission Factor (Natural Gas / Fuel Oil)	Case 1 All N.G (TPY)	Case 2 Limited F.O. + N.G. (TPY)	Limited PTE (TPY)	Emission Factor Source
PM	1.9 lb/MMCF	2.30	1.74	6.05	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	2 lb/kgal		4.31		AP-42, Ch. 1.3, 5/2010, Table 1.3-1
PM_{10} / Direct $PM_{2.5}$	7.6 lb/MMCF	9.20	6.96	14.07	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	3.3 lb/kgal		7.11		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 1.3-2
SO_2	0.6 lb/MMCF	0.73	0.55	86.22	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	39.76 lb/kgal		85.67		AP-42, Ch. 1.3, 5/2010, Table 1.3-1, 142S
VOC	5.5 lb/MMCF	6.66	5.03	6.66	AP-42, Ch. 1.4, 7/1998, Table 1.4-2
	0.252 lb/kgal		0.54		AP-42, Ch. 1.3, 5/2010, Table 1.3-3
CO	Emissions Set to Keep Nested Source under 100 TPY			85.90	Natural gas combustion is worst case.
NO_x	Emissions Set to Keep Nested Source under 100 TPY			83.20	Natural gas combustion is worst case.
CO_2	53.06 kg/MMBtu	144,382	109,221	159,053	40 CFR 98, Subpart C, Table C-1
	75.20 kg/MMBtu		49,832		40 CFR 98, Subpart C, Table C-1
CH_4	1.00E-03 kg/MMBtu	2.72	2.06	4.05	40 CFR 98, Subpart C, Table C-2
	3.00E-03 kg/MMBtu		1.99		40 CFR 98, Subpart C, Table C-2
N_2O	1.00E-04 kg/MMBtu	0.27	0.21	0.61	40 CFR 98, Subpart C, Table C-2
	6.00E-04 kg/MMBtu		0.40		40 CFR 98, Subpart C, Table C-2
CO_2e				159,336	Calculated

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Appendix A to the Technical Support Document - Emission Calculations

Limited Potential to Emit - Boiler #1 to #4 at Johnson Melloh Solutions - IMC Central Energy Plant

(Continued from Previous Page)

Limited Potential to Emit					
	Emission Factor (Natural Gas / Fuel Oil)	**Case 1 All N.G (TPY)**	**Case 2 Limited F.O. + N.G. (TPY)**	**Limited PTE (TPY)**	**Emission Factor Source**
	None	0.00	0.00		No emission factor
1,1,1-Trichloroethane	2.36E-04 lb/kgal		5.09E-04	5.09E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-05 lb/MMCF	2.90E-05	2.20E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
2-methylnaphthalene	None		0.00	2.90E-05	No emission factor
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
3-methylchloranthrene	None		0.00	2.18E-06	No emission factor
	1.60E-05 lb/MMCF	1.94E-05	1.46E-05		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
7,12-dimethylbenz(a)anthracene	None		0.00	1.94E-05	No emission factor
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthene	2.11E-05 lb/kgal		4.55E-05	4.71E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Acenaphthylene	2.53E-07 lb/kgal		5.45E-07	2.19E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.40E-06 lb/MMCF	2.90E-06	2.20E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Anthracene	1.22E-06 lb/kgal		2.63E-06	4.83E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.00E-04 lb/MMCF	2.42E-04	1.83E-04		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Arsenic	4.00E-06 lb/MMBtu		1.20E-03	1.39E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benz(a)anthracene	4.01E-06 lb/kgal		8.64E-06	1.03E-05	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	2.10E-03 lb/MMCF	2.54E-03	1.92E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzene	2.14E-04 lb/kgal		4.61E-04	2.54E-03	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1.45E-06	1.10E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(a)pyrene	None		0.00	1.45E-06	No emission factor
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(b)fluoranthene	None		0.00	2.18E-06	No emission factor
	1.20E-06 lb/MMCF	1.45E-06	1.10E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(g,h,i)perylene	2.26E-06 lb/kgal		4.87E-06	5.97E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Benzo(k)fluoranthene	None		0	2.18E-06	No emission factor
	1.20E-05 lb/MMCF	1.45E-05	1.10E-05		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Beryllium	3.00E-06 lb/MMBtu		9.02E-04	9.13E-04	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.10E-03 lb/MMCF	1.33E-03	1.01E-03		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Cadmium	3.00E-06 lb/MMBtu		9.02E-04	1.91E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.40E-03 lb/MMCF	1.69E-03	1.28E-03		AP-42, Ch. 1.4, Table 1.4-4, 7/1998
Chromium	3.00E-06 lb/MMBtu		9.02E-04	2.18E-03	AP-42, Ch. 1.3, Table 1.3-10, 5/2010
	1.80E-06 lb/MMCF	2.18E-06	1.65E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Chrysene	2.38E-06 lb/kgal		5.13E-06	6.78E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-06 lb/MMCF	1.45E-06	1.10E-06		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dibenzo(a,h)anthracene	1.67E-06 lb/kgal		3.60E-06	4.70E-06	AP-42, Ch. 1.3, Table 1.3-9, 5/2010
	1.20E-03 lb/MMCF	1.45E-03	1.10E-03		AP-42, Ch. 1.4, Table 1.4-3, 7/1998
Dichlorobenzene	None		0.00	1.45E-03	No emission factor
	None	0.00	0.00		No emission factor
Ethylbenzene	6.36E-05 lb/kgal		1.37E-04	1.37E-04	AP-42, Ch. 1.3, Table 1.3-9, 5/2010

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Appendix A to the Technical Support Document - Emission Calculations
Limited Potential to Emit - Boiler #1 to #4 at Johnson Melloh Solutions - IMC Central Energy Plant
(Continued from Previous Page)

	Potential to Emit				
	Emission Factor (Natural Gas / Fuel Oil)	**Case 1 All N.G (TPY)**	**Case 2 Limited F.O. + N.G. (TPY)**	**Limited PTE (TPY)**	**Emission Factor Source**
Fluoranthene	3.00E-06 lb/MMCF	3.63E-06	2.75E-06	1.32E-05	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	4.84E-06 lb/kgal		1.04E-05		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Fluorene	2.80E-06 lb/MMCF	3.39E-06	2.56E-06	1.22E-05	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	4.47E-06 lb/kgal		9.63E-06		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Formaldehyde	7.50E-02 lb/MMCF	9.08E-02	0.0687	0.200	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	0.061 lb/kgal		0.1314		AP-42, Ch. 1.3, Table 1.3-8, 5/2010
Hexane	1.8 lb/MMCF	2.18	1.65	2.18	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	None		0.00		No emission factor
Indo(1,2,3-cd)pyrene	1.80E-06 lb/MMCF	2.18E-06	1.65E-06	6.26E-06	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	2.14E-06 lb/kgal		4.61E-06		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Lead	None	0.00	0.00	2.71E-03	No emission factor
	9.00E-06 lb/MMBtu		2.71E-03		AP-42, Ch. 1.3, Table 1.3-10, 5/2010
Manganese	3.80E-04 lb/MMCF	4.60E-04	3.48E-04	2.15E-03	AP-42, Ch. 1.4, Table 1.4-4, 7/1998
	6.00E-06 lb/MMBtu		1.80E-03		AP-42, Ch. 1.3, Table 1.3-10, 5/2010
Mercury	2.60E-04 lb/MMCF	3.15E-04	2.38E-04	1.14E-03	AP-42, Ch. 1.4, Table 1.4-4, 7/1998
	3.00E-06 lb/MMBtu		9.02E-04		AP-42, Ch. 1.3, Table 1.3-10, 5/2010
Naphthalene	6.10E-04 lb/MMCF	7.38E-04	5.58E-04	2.99E-03	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	1.13E-03 lb/kgal		2.43E-03		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Nickel	2.10E-03 lb/MMCF	2.54E-03	1.92E-03	2.82E-03	AP-42, Ch. 1.4, Table 1.4-4, 7/1998
	3.00E-06 lb/MMBtu		9.02E-04		AP-42, Ch. 1.3, Table 1.3-10, 5/2010
Phenanthrene	1.70E-05 lb/MMCF	2.06E-05	1.56E-05	3.82E-05	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	1.05E-05 lb/kgal		2.26E-05		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Polycyclic Organic Matter	None	0.00	0.00	7.11E-03	No emission factor
	0.0033 lb/kgal		7.11E-03		AP-42, Ch. 1.3, Table 1.3-8, 5/2010
Pyrene	5.00E-06 lb/MMCF	6.05E-06	4.58E-06	1.37E-05	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	4.25E-06 lb/kgal		9.16E-06		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Selenium	2.40E-05 lb/MMCF	2.90E-05	2.20E-05	4.73E-04	AP-42, Ch. 1.4, Table 1.4-4, 7/1998
	1.50E-06 lb/MMBtu		4.51E-04		AP-42, Ch. 1.3, Table 1.3-10, 5/2010
Toluene	3.40E-03 lb/MMCF	4.11E-03	3.11E-03	1.67E-02	AP-42, Ch. 1.4, Table 1.4-3, 7/1998
	6.30E-03 lb/kgal		1.36E-02		AP-42, Ch. 1.3, Table 1.3-9, 5/2010
Xylene	None	0.00	0.00	2.35E-04	No emission factor
	1.09E-04 lb/kgal		2.35E-04		AP-42, Ch. 1.3, Table 1.3-9, 5/2010

Worst Case HAP at Limited PTE	**2.18**	**TPY**	**(Hexane)**
Total HAP at Limited PTE	**2.43**	**TPY**	

Methodology:
1) Throughput (MMCF/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/MMCF)
2) Throughput (kgal/yr) = Heat Input (MMBtu/hr) x 8,760 hr/yr x 1/Heat Content (MMBtu/kgal)
3) PTE (TPY) = Emission Factor (lb/MMCF) x Usage (MMCF/yr) x 1 ton/2,000 lb
4) PTE (TPY) = Emission Factor (lb/kgal) x Usage (kgal/yr) x 1 ton/2,000 lb
5) PTE (TPY) = Emission Factor (kg/MMBtu) x 2.2046 lb/kg x Usage (MMBtu/yr) x 1 ton/2,000 lb
6) CO_2e (TPY) = CO_2 Emissions + (CH_4 Emissions x Global Warming Potential (25)) + (N_2O Emissions x (Global Warming Potential 298))
7) Worst Case PTE (TPY) = Highest Potential Emission Rate (TPY) of Fuel Oil Combustion and Natural Gas Combustion for each pollutant.

Appendix A to the Technical Support Document - Emission Calculations
JMS Fire Pump Engines
Diesel Fuel < 600 HP

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International (	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Unit Location	horsepower		max heat input MMBtu / hr
Main Terminal -LAN Room	480	Fire Pump Engine # 1	
South Tug Guard Shack	480	Fire Pump Engine # 2	
Gate 10 Guard Shack	480	Fire Pump Engine # 3	
Midfield Road Access Gate	480	Fire Pump Engine # 4	
Main Terminal -Main Concourse	480	Fire Pump Engine # 5	
sum total	2400	hp	16.8
	16.8000	MMBtu/hr	

	PM	PM10/2.5	SOx	NOx	VOC	CO
Emission Factor lbs / MMBtu	0.31	0.31	0.29	4.41	0.36	0.95
Potential Emissions lbs / hr	5.21	5.21	4.87	74.09	6.05	15.96
tons / yr @ 500 hrs / yr	1.30	1.30	1.22	18.52	1.51	3.99

Methodology

AP-42 App. A Conversion Factor: 7.00E+03 Btu/horsepower hr
Emission Factor (lbs / MMBtu): from AP-42 Table 3.3-1 & 3.3-2 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines
Diesel fuel Btu: 140000 Btu/gal (per AP-42 Appendix A)
Potential Emissions (lbs / hr): emfac x heat input
Potential Emissions (tons / yr): lbs / hr emissions x 500 operating hrs / yr x ton / 2000 lbs
if limited to: 500 annual operating hours, then 16785.7 gal/yr max annual diesel fuel consumption

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/MMBtu	9.33E-04	4.09E-04	2.85E-04	3.91E-05	1.18E-03	7.67E-04	9.25E-05	1.68E-04
Potential Emission in tons/yr	3.92E-03	1.72E-03	1.20E-03	1.64E-04	4.96E-03	3.22E-03	3.89E-04	7.06E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Methodology

Potential Emission of Total HAPs (tons/yr)	1.63E-02

Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
JMS Large Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	1505.0	Emergency Generator # 1
Output Horsepower Rating (hp)	1505.0	Emergency Generator # 2
Output Horsepower Rating (hp)	1505.0	Emergency Generator # 3
Total	**4515.0**	

Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	2,257,500
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM*	PM10*	PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	7.00E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	2.40E-02 **see below	7.05E-04	5.50E-03
Potential Emission in tons/yr	0.79	0.45	0.45	2.74	27.09	0.80	6.21

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

**NOx emission factor: uncontrolled = 0.024 lb/hp-hr, controlled by ignition timing retard = 0.013 lb/hp-hr

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	6.13E-03	2.22E-03	1.52E-03	6.23E-04	1.99E-04	6.23E-05	1.68E-03

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**1.24E-02**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
VOC and Particulate
From Surface Coating Operations
AAR Ablative Coating Operation

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Material	Density (Lb/Gal)	Weight % Volatile (H20 & Organics)	Weight % Water	Weight % Organics	Volume % Water	Volume % Non-Volatiles (solids)	Gal of Mat. (gal/unit)	Maximum (unit/hour)	Pounds VOC per gallon of coating less water	Pounds VOC per gallon of coating	Potential VOC pounds per hour	Potential VOC pounds per day	Potential VOC tons per year	Particulate Potential (ton/yr)	lb VOC/gal solids	Transfer Efficiency
PR1200 RTV Primer	6.34	94.50%	0.0%	94.5%	0.0%	4.55%	0.25	1.00	5.99	5.99	1.50	35.95	6.56	0.10	131.68	75%
Ablative Coating (MA25S)	5.12	48.05%	0.0%	48.1%	0.0%	51.95%	1.77	1.00	2.46	2.46	4.35	104.51	19.07	5.16	4.74	75%
RTV 560	11.84	0.71%	0.0%	0.7%	0.0%	99.46%	2.00	1.00	0.08	0.08	0.17	4.04	0.74	0.00	0.08	100%
Acetone	6.59	100%	100.0%	0.0%	0.0%	0.00%	0.50	1.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	100%
State Potential Emissions			**Add worst case coating to all solvents**								**6.02**	**144.49**	**26.37**	**5.25**		
METHODOLOGY											**326 IAC 8-1-6 VOC Minor Limit**		**25.00**	**TPY**		

Pounds of VOC per Gallon Coating less Water = (Density (lb/gal) * Weight % Organics) / (1-Volume % water)
Pounds of VOC per Gallon Coating = (Density (lb/gal) * Weight % Organics)
Potential VOC Pounds per Hour = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr)
Potential VOC Pounds per Day = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (24 hr/day)
Potential VOC Tons per Year = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (8760 hr/yr) * (1 ton/2000 lbs)
Particulate Potential Tons per Year = (units/hour) * (gal/unit) * (lbs/gal) * (1- Weight % Volatiles) * (1-Transfer efficiency) *(8760 hrs/yr) *(1 ton/2000 lbs)
Pounds VOC per Gallon of Solids = (Density (lbs/gal) * Weight % organics) / (Volume % solids)
Total = Worst Coating + Sum of all solvents used

Appendix A to the Technical Support Document - Emission Calculations
HAP Emission Calculations
AAR Ablative Coating Operation

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Material	Density (lb/gal)	Gallons of Material (gal/unit)	Maximum (unit/hr)	Wt% Xylene	Wt% Ehtylbenzene	Wt% MIBK	Wt% Toluene	Xylene (TPY)	Ethylbenzene (TPY)	MIBK (TPY)	Toluene (TPY)
PR1200 RTV Primer	6.34	0.25	1	0.00%	0.10%	0.00%	0.10%	0.00	0.01	0.00	0.01
Ablative Coating (MA25S)	5.12	1.77	1	2.00%	0.00%	3.00%	14.00%	0.79	0.00	1.19	5.56
RTV 560	11.84	2	1	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Acetone	6.59	0.5	1	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
							Total Single HAP	**0.79**	**0.01**	**1.19**	**5.56**
							Total HAP		**7.56**		

Appendix A to the Technical Support Document - Emission Calculations
Natural Gas Combustion Only
MM BTU/HR <100
AAR AMU Heat & Cure Oven

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
2.50	1000	21.9

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Potential Emission in tons/yr	0.02	0.08	0.08	0.01	1.10	0.06	0.92

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.

PM2.5 emission factor is filterable and condensable PM2.5 combined.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

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

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	2.3E-05	1.3E-05	8.2E-04	2.0E-02	3.7E-05

	HAPs - Metals				
	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	5.5E-06	1.2E-05	1.5E-05	4.2E-06	2.3E-05

Total HAPs 0.021

The five highest organic and metal HAPs emission factors are provided above.

Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A to the Technical Support Document - Emission Calculations
VOC and Particulate
Surface Coating Operation P-2

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Material	Density (Lb/Gal)	Weight % Volatile (H20 & Organics)	Weight % Water	Weight % Organics	Volume % Water	Volume % Non-Volatiles (solids)	Gal of Mat. (gal/unit)	Maximum (units/hour)	Pounds VOC per gallon of coating less water	Pounds VOC per gallon of coating	Potential VOC tons per year	Particulate Potential (ton/yr)	lb VOC/gal solids	Transfer Efficiency
Stripper PR-2002	8.34	100.00%	44.4%	55.6%	44.4%	0.00%	110.0	0.0041	8.34	4.64	9.18	0.00	0.00	0%
Primer	13.39	21.30%	0.0%	21.3%	0.0%	52.40%	14.0	0.0041	2.85	2.85	0.72	0.27	5.44	90%
White Topcoat	11.12	26.00%	0.0%	26.0%	0.0%	57.92%	24.0	0.0041	2.89	2.89	1.25	0.36	4.99	90%
Gray Topcoat	11.02	23.50%	0.0%	23.5%	0.0%	62.80%	20.0	0.0041	2.59	2.59	0.93	0.30	4.12	90%

State Potential Emissions **Add worst case coating to all solvents** **see below** **0.92**

METHODOLOGY

Primer (14 gallons) + White Topcoat (24 gallons) + Gray Topcoat (20 gallons) = 58 gallons to paint one unit (plane).
Units/hour = max of 36 planes painted per year = 36 units/yr / year/8760 hours = 0.0041 units/hour.
Pounds of VOC per Gallon Coating less Water = (Density (lb/gal) * Weight % Organics) / (1-Volume % water)
Pounds of VOC per Gallon Coating = (Density (lb/gal) * Weight % Organics)
Potential VOC Pounds per Hour = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr)
Potential VOC Pounds per Day = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (24 hr/day)
Potential VOC Tons per Year = Pounds of VOC per Gallon coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (8760 hr/yr) * (1 ton/2000 lbs)
Particulate Potential Tons per Year = (units/hour) * (gal/unit) * (lbs/gal) * (1- Weight % Volatiles) * (1-Transfer efficiency) *(8760 hrs/yr) *(1 ton/2000 lbs)
Pounds VOC per Gallon of Solids = (Density (lbs/gal) * Weight % organics) / (Volume % solids)
Total = Worst Coating + Sum of all solvents used
Transfer Efficiency = Air Pollution Engineering Manual (AWMA 1992) Chapter 10 Table 2, electrostatic painting and flat surfaces.

326 IAC 8-1-6 VOC Minor Limit:
IDEM, OAQ determined a VOC limit was required to ensure this operation does not exceed 25 tons per year. A limit was added under SPM 097-28213-00559.

Potential to Emit VOC	**greater than**	**25**	TPY
VOC Limit		**25**	TPY

Appendix A to the Technical Support Document - Emission Calculations
HAP Emission Calculations
AAR Surface Coating Operation P-2

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Grou	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek
Date: December 10, 2014

Material	Density (Lb/Gal)	Gallons of Material (gal/unit)	Maximum (units/hour)	Weight % Xylene	Weight % MIBK	Weight % Formaldehyde	Weight % Benzene	Weight % Hexane	Weight % Glycol Ethers	Weight % Methanol	Xylene Emissions (ton/yr)	MIBK Emissions (ton/yr)	Formaldehyde Emissions (ton/yr)	Benzene Emissions (ton/yr)	Hexane Emissions (ton/yr)	Glycol Ethers Emissions (ton/yr)	Methanol Emissions (ton/yr)	Combined HAP (ton/yr)
White Topcoat	11.12	24.00	0.0041	5.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.24
Gray Topcoat	11.02	20.00	0.0041	5.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.20	0.40	0.00	0.00	0.00	0.00	0.00	0.60
METHODOLOGY											**0.44**	**0.40**						**0.84**

Potential HAP = Weight % HAP * Density of coating (lb/gal) * Gal of Material (gal/unit) * Maximum (units/hr) * (8760 hr/yr) * (1 ton/2000 lbs)

Appendix A to the Technical Support Document - Emission Calculations
Natural Gas Combustion Only
MM BTU/HR <100
AAR NG Make-Up Air Heating Unit B-1

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road
	Permit Reviewer:	David Matousek
	Date:	December 10, 2014

Combined Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
36.0	315.36

	Pollutant					
	PM*	PM10/2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100.0 **see below	5.5	84.0
Potential Emission in tons/yr	0.30	1.20	0.09	15.77	0.87	13.25

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.

**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

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 (SUPPLEMENT D 3/98)

Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMCF	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	3.3E-04	1.9E-04	1.2E-02	2.8E-01	5.4E-04

	HAPs - Metals					Combined
	Lead	Cadmium	Chromium	Manganese	Nickel	HAP
Emission Factor in lb/MMCF	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	NA
Potential Emission in tons/yr	7.9E-05	1.7E-04	2.2E-04	6.0E-05	3.3E-04	0.30

The five highest organic and metal HAPs emission factors are provided above. Hexane is highest single HAP.

Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A to the Technical Support Document - Emission Calculations

Emission Calculations - Surface Coating Operations EU-13, EU17 and EU-18

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	T097-35016-00156	2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive
Johnson Melloh Solutions (JMS)	T097-34078-00586	2745 South Hoffman Road, Suite 504
AAR Aircraft Services, Indianapolis (AAR)	T097-33261-00559	2825 West Perimeter Road
Chautauqua Airlines (CHA)	T097-35018-00668	2745 South Hoffman Road, Dock 67, Hng 7A-7B
ASIG Aircraft Services International Group	T097-35006-00667	2050 South Hoffman Road

Permit Reviewer: David Matousek

Date: December 10, 2014

Aircraft Equivalence										
Aircraft	Bays per Fleet	Planes per Year (HMV)	Planes per Year (CCHK)	Planes per Year (Corrosion)		Planes per Year (Other)	HMV ISS Factor	HMV ISS Aircraft Equivalence	CCHK ISS Factor	CCHK ISS Aircraft Equivalence
757	3	35	96	0		1.5	1.786	62.51	1.80	172.80
767	2	24	48	0		0.5	2.700	64.80	2.70	129.60
737	12	96	265	41		3.5	1.000	96.00	1.00	265.00

HMV Aircraft Total per Year 223.31

CCHK Aircraft Total per Year 567.40

PM, PM_{10}, $PM_{2.5}$ Emissions

Hanger Floor Emissions			
Aircraft	Particulate Emissions (lb/plane)	Planes per Year	PTE PM, PM_{10}, $PM_{2.5}$ (TPY)
757-HMV	94.40	35	1.65
767-HMV	141.60	24	1.70
737-HMV	52.40	96	2.52
757-CCHK	83.00	96	3.98
767-CCHK	92.40	48	2.22
737-CCHK	55.30	265	7.33
737-RCHK	14.80	41	0.30
		PTE (TPY)	19.70

Paint Room Emissions			
Aircraft	Particulate Emissions (lb/plane)	Planes per Year	PTE PM, PM_{10}, $PM_{2.5}$ (TPY)
757-HMV	220.33	35	3.86
767-HMV	245.30	24	2.94
737-HMV	146.89	96	7.05
		PTE (TPY)	13.85

(Continued on Next Sheet)

Appendix A to the Technical Support Document (TSD)
Emission Calculations - Surface Coating Operations EU-13, EU17 and EU-18
(Continued from Previous Sheet)

Strip/Surface Emissions			
Aircraft	**Particulate Emissions (lb/plane)**	**Planes per Year**	**PTE PM, PM_{10}, $PM_{2.5}$ (TPY)**
757-HMV	156.10	35	2.73
767-HMV	156.10	24	1.87
737-HMV	154.13	96	7.40
		PTE (TPY)	**12.00**

Emissions from Other Operations			
Aircraft	**Particulate Emissions (lb/plane)**	**Planes per Year**	**PTE PM, PM_{10}, $PM_{2.5}$ (TPY)**
757-HMV	190.33	35	3.33
767-HMV	213.56	24	2.56
737-HMV	135.11	96	6.49
		PTE (TPY)	**12.38**

Emission Unit Total			
Operation	**PTE (TPY)**	**Control %**	**Controlled PTE (TPY)**
Hanger Floor	19.70	0%	19.70
Paint Room	13.85	95%	0.69
Strip/Surface	12.00	95%	0.60
Other	12.38	95%	0.62
Total PTE (TPY)	57.93		21.61

VOC and HAP Emissions

VOC Emissions			
Shop	**Emissions (lb/plane)**	**Planes Per Year**	**PTE (TPY)**
Interior Shop	64.33		18.54
All other Interior Shop	20.35		5.86
Machine Rework	2.15		0.62
Paint Shop Paint Booth	146.86		42.32
Other Shops in Paint Shop	8.48		2.44
Heat Exchanger	19.35		5.58
Metal Fabricator	38.47		11.09
All other indirect Shops	28.86	576.37	8.32
		PTE VOC (TPY)	**94.77**

HAP	Wt. % HAP in VOC Emissions	Total VOC (TPY)	HAP PTE (TPY)
Toluene	0.97%		0.92
Xylene	0.24%		0.23
Methyl Isobutyl Ketone	0.34%		0.32
Chromium	0.55%		0.52
Diisocyanate	0.01%		0.01
Methyl Chloroform	1.00%		0.95
Phenol	0.08%		0.08
Ethylbenzene	0.01%		0.01
Glycol	0.01%		0.01
Methylene Chloride	0.43%		0.41
Methanol	0.01%	94.77	0.01
		Total HAP (TPY)	**3.47**

Appendix A to the Technical Support Document - Emission Calculations
ASIG Large Reciprocating Internal Combustion Engines - Generator 017
Output Rating (>600 HP)

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**

Permit Reviewer: David Matousek

Date: December 10, 2014

Output Horsepower Rating (hp)	1256
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	628,000
Sulfur Content (S) of Fuel (% by weight)	0.300

	Pollutant						
	PM**	PM10*	PM2.5*	SO2	NOx**	VOC	CO**
Emission Factor in lb/hp-hr	8.82E-04	4.01E-04	4.01E-04	2.43E-03 *(.00809S)*	1.52E-02	7.05E-04	1.87E-02
Potential Emission in tons/yr	0.28	0.13	0.13	0.76	4.77	0.22	5.87

*PM10 emission factor in lb/hp-hr was calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

**PM, NOx and CO emission factors taken from 40 CFR 60, Subpart IIII

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	1.71E-03	6.18E-04	4.24E-04	1.73E-04	5.54E-05	1.73E-05	4.66E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)

****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**3.46E-03**

Methodology

Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Appendix A to the Technical Support Document - Emission Calculations
ASIG Tank Storage VOC losses

Collocated Sources:	Permit Numbers	Address - Indianapolis, Indiana 46241
Indianapolis Airport Authority (IAA)	**T097-35016-00156**	**2825 West Perimeter Road and 7800 Col. H. Weir Cook Drive**
Johnson Melloh Solutions (JMS)	**T097-34078-00586**	**2745 South Hoffman Road, Suite 504**
AAR Aircraft Services, Indianapolis (AAR)	**T097-33261-00559**	**2825 West Perimeter Road**
Chautauqua Airlines (CHA)	**T097-35018-00668**	**2745 South Hoffman Road, Dock 67, Hng 7A-7B**
ASIG Aircraft Services International Group	**T097-35006-00667**	**2050 South Hoffman Road**
Permit Reviewer:	**David Matousek**	
Date:	**December 10, 2014**	

Three identical above ground Jet A fuel storage tanks

TANKS 4.09d
Emissions Report - Summary Format

Tank	
Tank Identification	TK1
User Identification:	Jet A fuel storage tank
Type of Tank:	Vertical Fixed Roof Tank
Description:	Jet A fuel storage tank
Tank Dimensions	
Shell Height (ft):	40
Diameter (ft):	44.5
Liquid Height (ft):	38
Avg. Liquid Height (ft):	19
Volume (gal):	465,000
Turnovers:	54.46
Net Throughput (gal/yr):	25,342,500
Heated tank (y/n?)	n
Paint Characteristics	
Shell Color/Shade:	White
Shell Condition:	Good
Roof Color/Shade	White
Roof Condition	Good
Roof Characteristics	
Type	Cone
Height (ft):	2
Slope (ft/ft) (Cone Roof)	0.09
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03
Daily Liquid Surface Temp (F)	
Avg.:	54
Min.:	48.9
Max.:	59.1
Liquid Bulk Temp (F):	52.3
Vapor Pressure (psia):	
Avg.:	0.007
Min.:	0.0058
Max.:	0.0083
Vapor Molecular Wt.:	130
Molecular Wt.:	162

	Losses (lbs/yr)		
Components	**Working Loss**	**Breathing Loss**	**Total**
Jet A Fuel	**394.17**	**71.93**	**466.09**

Combined Losses (tons/yr) for 3 identical storage tanks		
Working Loss	**Breathing Loss**	**Total**
0.59	**0.11**	**0.70**

Methodology
Emission calculations based on EPA program "TANKS" Version 4.09d
Parameters per application

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Travis Murphy
Johnson Melloh Solutions - IMC Central Energy Plant
5925 Stockberger Place
Indianapolis, IN 46241

DATE: February 11, 2015

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

SUBJECT: Final Decision
Title V - Renewal Administrative Permit
097 - 34078 - 00586

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:
Nick Melloh, President
Anthony Kunkler Keramida Environmental
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

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

February 11, 2015

TO: Wayne Township Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Johnson Melloh Solutions - IMC Central Energy Plant
Permit Number: 097 - 34078 - 00586

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	LPOGOST 2/11/2015 Johnson Melloh Solutions - IMC Central Energy Plant 097 - 34078 - 00586 final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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1		~~Travis Murphy Johnson Melloh Solutions - IMC Central Energy Plan 5925 Stockberger Place Indianapolis IN 46241 (Source CAATS)~~ Via USPS certified mail									
2		Nick Melloh President Johnson Melloh Solutions - IMC Central Energy Plan 5925 Stockberger Place Indianapolis IN 46241 *(RO CAATS)*									
3		Marion County Health Department 3838 N, Rural St Indianapolis IN 46205-2930 *(Health Department)*									
4		Indianapolis City Council 200 East Washington Street, Room E Indianapolis IN 46204 *(Local Official)*									
5		Marion County Commissioners 200 E. Washington St. City County Bldg., Suite 801 Indianapolis IN 46204 *(Local Official)*									
6		Wayne Township Public Library 198 South Girl School Rd. Indianapolis IN 46231 *(Library)*									
7		Matt Mosier Office of Sustainability City-County Bldg/200 E Washington St. Rm# 2460 Indianapolis IN 46204 *(Local Official)*									
8		Anthony Kunkler Keramida Environmental, Inc. 401 North College Avenue Indianapolis IN 46202 *(Consultant)*									
9		Johan & Susan Van Den Heuvel 4409 Blue Creek Drive Carmel IN 46033 *(Affected Party)*									
10		Fairfield Builders Supply Corp PO Box 4427 Lafayette IN 47903 *(Affected Party)*									
11		Indiana Members Credit Union 5103 Madison Avenue Indianapolis IN 46227 *(Affected Party)*									
12											
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