INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

TO: Interested Parties / Applicant

DATE: March 27, 2014

RE: Jet Corr, Inc./127-33924-00094

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

Notice of Decision: Approval – Effective Immediately

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

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

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

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

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

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

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

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

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

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

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

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

Enclosures
FNTVOP.dot 6/13/2013

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Michael R. Pence
Governor

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Commissioner

Part 70 Operating Permit
OFFICE OF AIR QUALITY

Jet Corr Incorporated
3155 State Road 49
Valparaiso, Indiana 46383

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

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

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

Operation Permit No.: T127-33924-00094	
Issued by: Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Issuance Date: March 27, 2014 Expiration Date: March 27, 2019

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.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 corrugated box manufacturing and 100% recycled mill source.

Source Address:	3155 State Road 49, Valparaiso, Indiana 46383
General Source Phone Number:	219-548-9191
SIC Code:	2653, 2631
County Location:	Porter
Source Location Status:	Nonattainment for 8-hour ozone standard 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 Greenhouse Gas (GHG) potential to emit (PTE) is equal to or more than one hundred thousand (100,000) tons of CO2 equivalent (CO2e) emissions per year 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 Primary operation is not 1 of 28 Source Categories

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

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

(a) One (1) 3-color 48-inch flexographic printer-folder-gluer machine, identified as EU 003, installed in 1999, capacity: 250 sheets per minute.

(b) One (1) 4-color 48-inch flexographic printer-folder-gluer machine, identified as EU 004, installed in 1999, capacity: 250 sheets per minute.

(c) One (1) 94.5-inch EMBA press, identified as EU 005, installed in 1999, capacity: 957 feet per minute.

(d) One (1) 2-color flexographic printer-folder-gluer machine, identified as EU 012, installed in 2001, capacity: 100 sheets per minute at 89 inches by 205 inches, capacity: 1,708.33 feet per minute line speed.

(e) One (1) flexographic printer-folder-gluer machine, identified as EU 018, installed in 2001, capacity: 79.2 million square inches of paper per hour.

(f) One (1) flexographic model 170 folder gluer machine, identified as EU 019, installed in 2003, capacity: 925 feet per minute line speed.

(g) One (1) baler system, identified as EU 009, installed in 2000, modified in 2003, with a

capacity of 6,400 pounds of trimmings per hour, with one (1) identical backup baler to be utilized only in the event of failure of the primary baler unit. The baler system is equipped with a trimmings recovery cyclone and exhausted to Stack S003. As an accepted alternative operating scenario, the cyclone will exhaust to a baghouse and then back into the building.

(h) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 001, installed in 1999, rated at 20.92 million British thermal units per hour, exhausted through Stack S001.

(i) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 013, installed in 2001, rated at 20.92 million British thermal units per hour, exhausted through Stack S002.

(j) One (1) flexographic printer-folder-gluer machine, identified as EU 021, installed in 2006, capacity: 64.2 million square inches of paper per hour.

New Emission Units Permitted in 2014

(k) One (1) natural gas fired-boiler, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The boiler will be equipped with a continuous emissions monitoring system (CEMS) for NOx and diluent gas (O_2 or CO_2). [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

(l) One (1) paper machine designed to produce linerboard and medium from waste paper, identified as EU 029, permitted in 2014, with a maximum throughput of 1600 tons of air dried finished product per day and exhausting to stack S 029.

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

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

(a) Natural gas-fired combustion sources each with heat input equal to or less than ten million (10,000,000) British thermal units per hour, consisting of six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively identified as EU 011, rated at 39.23 million British thermal units per hour total [326 IAC 2-8-4].

(b) One (1) cold solvent degreaser, identified as EU 007, installed in 1999 [326 IAC 8-3-2, 326 IAC 8-3-8].

(c) Rotary die cutters, identified as EU 008, installed 1999, 2001 and 2009 [326 IAC 6-3].

(d) Starch silo, equipped with a baghouse, installed in 1999 [326 IAC 6-3].

(e) Two (2) paper corrugating machines, identified as EU 006, installed in 2001.

New Insignificant Emission Units Permitted in 2014

(f) One (1) biogas flare, identified as EU 025, permitted in 2014, with a throughput of 216,000scf of biogas per day (153.9 MMBtu/day) and exhausting to stack S 025.

(g) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (HP) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60,

Subpart IIII, the fire pump engine is considered new affected source]

(h) Three (3) natural gas-fired air make up units, identified as EU 030, permitted in 2014, with a combined capacity of 10 MMBtu per hour, exhausting through Stack S030.

(i) One (1) Starch silo, identified as EU 022, permitted in 2014, with a maximum throughput of 2.75 tons of starch per hour and equipped with a baghouse and exhausting to stack S 022.

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

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

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

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

SECTION B GENERAL CONDITIONS

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

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

B.2 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, T127-33924-00094, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

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

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

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Northwest Regional Office phone: (219) 464-0233; fax: (219) 464-0553**.**

(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 T127-33729-00094 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

(b) Provided that all terms and conditions are accurately reflected in this combined permit, all previous registrations and permits are superseded by this combined new source review and part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

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

The Permittee's right to operate this source terminates with the expiration of 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] [40 CFR 72]

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

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

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

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

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

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

B.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.

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

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

(a) The requirements to obtain a source modification approval under 326 IAC 2-7-10.5 or a permit modification under 326 IAC 2-7-12 are satisfied by this permit for the proposed emission units, control equipment or insignificant activities in Sections A.2 and A.3.

(b) Pursuant to 326 IAC 2-1.1-9 any permit authorizing construction may be revoked if construction of the emission unit has not commenced within eighteen (18) months from the date of issuance of the permit, or if during the construction, work is suspended for a continuous period of one (1) year or more.

B.25 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]

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

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

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

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

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

C.6 Stack Height [326 IAC 1-7]

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

C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(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.8 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.9 Compliance Requirements [326 IAC 2-1.1-11]

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

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

C.10 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

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

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

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

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

C.12 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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.13 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.14 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, not subject to CAM, in this permit:

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

C.15 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.16 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

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

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

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

The statement must be submitted to:

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

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

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

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, 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.18 General Reporting Requirements [326 IAC 2-7-5(3)(C)][326 IAC 2-1.1-11] [326 IAC 2-2] [326 IAC 2-3]

(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.19 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) One (1) 3-color 48-inch flexographic printer-folder-gluer machine, identified as EU 003, installed in 1999, capacity: 250 sheets per minute.

(b) One (1) 4-color 48-inch flexographic printer-folder-gluer machine, identified as EU 004, installed in 1999, capacity: 250 sheets per minute.

(c) One (1) 94.5-inch EMBA press, identified as EU 005, installed in 1999, capacity: 957 feet per minute.

(d) One (1) 2-color flexographic printer-folder-gluer machine, identified as EU 012, installed in 2001, capacity: 100 sheets per minute at 89 inches by 205 inches, capacity: 1,708.33 feet per minute line speed.

(e) One (1) flexographic printer-folder-gluer machine, identified as EU 018, installed in 2001, capacity: 79.2 million square inches of paper per hour.

(f) One (1) flexographic model 170 folder gluer machine, identified as EU 019, installed in 2003, capacity: 925 feet per minute line speed.

(j) One (1) flexographic printer-folder-gluer machine, identified as EU 021, installed in 2006, capacity: 64.2 million square inches of paper per hour.

Insignificant Activities:

(e) Two (2) paper corrugating machines, identified as EU 006, installed in 2001.

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

The total VOC content delivered to the printing and gluing operations, identified as EU 003, EU 004, EU 005, EU 012, EU 018, EU 019, and EU021, including the two (2) corrugating machines, identified as EU 006 (deemed insignificant activities) shall be limited to less than 20.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with this limit will limit the potential VOC emissions from the printing and glue operation and combined with the potential to emit VOC from the paper corrugating machine to less than 25 tons per year and render the requirements of 326 IAC 2-3 not applicable to 1999, 2001, 2003 and 2006 Modification.

D.1.2 Hazardous Air Pollutants Minor Limits [40 CFR 63] [326 IAC 2-4.1]

The single Hazardous Air Pollutant (HAP) delivered to the printing and gluing operations, shall be limited to less than ten (10) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with the above limit and the potential HAPs emissions from the other emission units will limit the source-wide HAPs emission to less than ten (10) tons per year of a single HAP and less than twenty-five (25) tons per year of a combination of HAPs and make the source an area source of HAPs.

D.1.3 Graphic Arts Operations [326 IAC 8-5-5]

Pursuant to 326 IAC 8-5-5 (Graphic Arts Operations), the Permittee may not cause, allow, or permit the operation of the facility unless the Permittee uses one of the following types of compliant coatings:

(a) The volatile fraction of the ink, as it is applied to the substrate, contains twenty-five percent (25%) by volume or less of VOC, and seventy-five percent (75%) by volume or more of water; or

(b) The ink as it is applied to the substrate, less water, contains sixty percent (60%) by volume or more nonvolatile material; or

(c) The ink, as applied to the substrate, meets an emission limit of five-tenths (0.5) pounds of VOC per pound of solids in the ink.

D.1.4 Graphic Arts Operations [326 IAC 8-5-5]

Pursuant to 326 IAC 8-5-5(f), work practices for flexographic printers, identified as EU 003, EU 004, EU 012, EU 018, EU 019, EU 019 EU 021 and EMBA Press, identified as EU 005 shall include, but not be limited to, the following:

(a) When not in use, all cleaning materials shall be kept in closed containers.

(b) Cleaning materials shall be conveyed from one (1) location to another in closed containers or pipes.

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

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

Compliance Determination Requirements

D.1.6 Volatile Organic Compounds (VOC) and Hazardous Air Pollutants (HAPs)

Compliance with the VOC and HAPs usage limitations contained in Conditions D.1.1, D.1.2 and D.1.3 shall be determined pursuant to 326 IAC 8-1-4(a)(3) and 326 IAC 8-1-2(a) by preparing or obtaining from the manufacturer the copies of the “as supplied” and “as applied” VOC data sheets. IDEM, OAQ reserves the authority to determine compliance using Method 24 in conjunction with the analytical procedures specified in 326 IAC 8-1-4.

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

D.1.7 Record Keeping Requirement

(a) To document the compliance status with Conditions D.1.1 and D.1.2, the Permittee shall maintain records in accordance with (1) through (4) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the VOC and HAPs usage limits established in Conditions D.1.1 and D.1.2.

(1) The VOC and HAP content of each coating material and solvent used.

(2) The amount of coating material and solvent used less water on monthly basis. Records shall include purchase orders, invoices, and material safety data sheets (MSDS) necessary to verify the type and amount used.

(3) The total VOC and HAPs usage for each month; and

(4) The weight of VOCs and HAPs emitted for each compliance period.

(b) To document the compliance status with Condition D.1.3, pursuant to 326 IAC 8-1-10(c) (Compliance Certification, Record Keeping and Reporting Requirements for Certain Coating Facilities Using Compliant Coatings), the Permittee shall for each coating facility and for each coating used collect and record each day and maintain all of the following information:

(1) The name and identification number of each coating, as applied;

(2) The mass of VOC (excluding water and exempt compounds) per volume of coating for each coating, as applied, or the VOC content of each coating, as applied, expressed in units necessary to determine compliance;

(3) As new compliant coatings are added to a coating facility, the records required by this condition shall be updated to include the new coating; and

(4) If use of a coating is discontinued, the records required by this section shall be maintained consistent with 326 IAC 8-1-9(c).

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

D.1.8 Reporting Requirements

Pursuant to 326 IAC 8-5-5(a)(3)(A), the source located in Porter County shall comply with the requirements of 326 IAC 8-7-2(c) that requires compliance with 326 IAC 8-7-6 and 326 IAC 8-1-9(b). These rules require the following:

(a) Pursuant to 326 IAC 8-7-6, each source or facility shall submit to the IDEM, OAQ a certification that the facility is exempt from the requirements of 326 IAC 8-7-3. The certification shall contain all of the following information:

(1) The name and address of the source and the name and telephone number of the company representative.

(2) Identification of each VOC emitting facility together with a description of the purpose each facility serves.

(3) A listing of facilities which meet the requirements of section 2(a) of this rule.

(4) Baseline actual emissions for each facility identified in subdivision (3) together with the following information:

(A) Maximum design rate, maximum production, or maximum throughput.

(B) VOC emission factors with reference to the source of the emission factors and procedures as to how the emission factors were estimated, for example, the type of each fuel or process chemicals used and the baseline year used.

(5) Procedures that will be used to monitor the source's potential emissions to ensure that they remain below twenty-five (25) tons per year.

(b) Pursuant to 326 IAC 8-1-9(b), records required by 326 IAC 8-1-9 or records required to show that a source is exempt from the requirements of 326 IAC 8, shall be submitted to the IDEM, OAQ or the U.S. EPA within thirty (30) days of the receipt of a written request.

D.1.9 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.1.1 and D.1.2 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) One (1) baler system, identified as EU 009, installed in 2000, modified in 2003, with a capacity of 6,400 pounds of trimmings per hour, with one (1) identical backup baler to be utilized only in the event of failure of the primary baler unit. The baler system is equipped with a trimmings recovery cyclone and exhausted to Stack S003. As an accepted alternative operating scenario, the cyclone will exhaust to a baghouse and then back into the building.

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

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the baler system shall not exceed 8.94 pounds per hour when operating at a process weight rate of 3.2 tons per hour.

The pounds per hour limitation was calculated with the following equation:

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

$E = 4.10\ P^{0.67}$

Where:
E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

D.2.2 Prevention of Significant deterioration (PSD) Minor Limits [326 IAC 2-2]

The permittee shall comply with the following:

The PM_{10} emissions from the baler system shall not exceed 8.94 pounds per hour.

Compliance with the above limit in combination with and the potential PM_{10} emissions from other emission units shall limit the sourcewide PM_{10} emissions to less than 250 tons per year and render the requirements of 326 IAC 2-2 (PSD) not applicable to the entire source.

D.2.3 Preventive Maintenance Plan [326 IAC 1-6-3]

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

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

D.2.4 Visible Emissions Notations

(a) Visible emission notations of the baler system stack exhaust S003 shall be performed during normal daylight operations once per day when the baler system is in operation and exhausting to the atmosphere. 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 reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

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

D.2.5 Record Keeping Requirement

(a) To document the compliance status with Condition D.2.4 - Visible Emission Notation, the Permittee shall maintain a daily record of visible emission notations of the baler system stack exhaust S003 when the baler system is in operation and exhausting to the atmosphere. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 001, installed in 1999, rated at 20.92 million British thermal units per hour, exhausted through Stack S001.

(i) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 013, installed in 2001, rated at 20.92 million British thermal units per hour, exhausted through Stack S002.

(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 Nitrogen Oxides (NO_X) [326 IAC 2-3]

The No. 2 fuel oil usage to the two (2) boilers, identified as EU 001 and EU 013 shall be limited to less than 350 kilo gallons per twelve (12) consecutive month period, with compliance determined at the end of each month, and the NOx emissions shall not exceed 20 pounds per kilo gallons of No. 2 fuel oil.

Compliance with the above limits in combination with the potential NOx emissions from other emission units will limit the sourcewide NOx emissions to less than 100 tons per year and render the requirements of 326 IAC 2-3 (Emission Offset) not applicable to the entire source.

D.3.2 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations), the SO_2 emissions from the 20.92 million British thermal units per hour boilers, identified EU 001 and EU 013, when combusting fuel oil, shall each not exceed five tenths (0.5) pounds per million British thermal units heat input. Pursuant to 326 IAC 7-2-1, compliance shall be demonstrated on a calendar month average.

D.3.3 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating:), particulate emissions from the two (2) boilers, identified as EU 001 and EU 013 shall not exceed 0.413 pounds per million Btu heat input (lb/MMBtu).

D.3.4 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.3.5 Sulfur Dioxide Emissions and Sulfur Content

Compliance with Condition D.3.2 shall be determined utilizing one of the following options:

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pound per million British thermal units 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 proce-

dures 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 the other method.

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

D.3.6 Visible Emissions Notations

(a) Visible emission notations of the boiler stack exhausts S001 and S002 shall be performed once per day during normal daylight operations when combusting No. 2 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 reasonable response steps. Failure to take response steps shall be considered a deviation from this permit. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.

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

D.3.7 Record Keeping Requirement

(a) To document compliance with Conditions D.3.1 and D.3.2, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken monthly and shall be complete and sufficient to establish compliance with the NO_X and SO_2 emission limits established in Conditions D.3.1 and D.3.2.

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

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications represent all of the fuel combusted during the period. The natural gas fired boiler certification does require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1(1); and

If the 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; and

(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

(b) To document the compliance status with Condition D.3.6 - Visible Emission Notation, the Permittee shall maintain a daily record of visible emission notations of the boiler stack exhausts S001 and S002 when combusting No. 2 fuel oil. 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).

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

D.3.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.3.1(b) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) One (1) natural gas fired-boiler, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The boiler will be equipped with a continuous emissions monitoring system (CEMS) for NOx and diluent gas (O_2 or CO_2). [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

(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.4.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 127-33729-00094 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired boiler, identified as EU 028 shall be as follows:

The GHGs BACT for the Boiler shall be as follows:

(a) The use of natural gas and biogas only,

(b) Implementation of an energy efficient design

(c) Good operating and combustion practices;

(d) Boiler designed for 74% thermal efficiency (HHV);

(e) The emission rate shall not exceed 117 lbs CO2 per MMBtu/hour; and

(f) The total CO_2 emissions from the natural gas-fired boiler shall not exceed 179,392 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

D.4.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating:), particulate emissions from the boiler, identified as EU 028, shall not exceed 0.23 pounds per million Btu heat input (lb/MMBtu).

D.4.3 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.4.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.4.1(d) – GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than 180 days after initial startup, the Permittee shall perform thermal efficiency testing of the boiler, identified as EU 028 utilizing methods approved by the Commissioner. These tests shall be conducted once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing

required by this condition.

D.4.5 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.4.1(f), the following equation shall be used to determine the CO_2e emissions from the Boiler, identified as EU 028 for each fuel type combusted:

CO_2e emissions (ton/month) = [(Fuel Usage (mmscf/month) x Heat Content (mmbtu/mmscf)) x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu) x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (mmscf/month) = monthly boiler fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42, 40 CFR Subpart C or vendor data, if available.

CO_2 EF (117.0 lb/mmbtu natural gas, 114.8 lb/mmbtu biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CH_4 EF (2.2E-03 lb/mmbtu natural gas, 7.1E.03 lb/mmbtu biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
N_2O EF (2.2E-04 lb/mmbtu natural gas, 1.4E.03 lb/mmbtu biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CO_2 GWP = 1 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

As alternative to calculating monthly CO_2 emissions using the above equation, the Permittee may use the monthly CO_2 emissions monitored and recorded using the continuous emission monitoring system required by Condition D.4.6.

D.4.6 Maintenance of Continuous Emission Monitoring Systems [326 IAC 3-5][326 IAC-2-2-3]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx and O_2 or CO_2 emissions.

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

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

(d) Whenever a NOx, or O_2 or CO_2 CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

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

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

D.4.7 Record Keeping Requirements

(a) To document the compliance status with Condition D.4.1(f) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_2e emissions from the natural

gas-fired boiler.

(b) To document the compliance status with Condition D.4.6 - Maintenance of Continuous Emission Monitoring System, 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.

(c) In the event that a breakdown of the NOx and O_2 or CO_2 continuous emission monitoring system (CEMS) occurs in Condition D.4.6 - Maintenance of Continuous Emission Monitoring System, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.4.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.4.1(f) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(l) One (1) paper machine designed to produce linerboard and medium from waste paper, identified as EU 029, permitted in 2014, with a maximum throughput of 1600 tons of air dried finished product per day and exhausting to stack S 029.

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

Pursuant to 326 IAC 8-1-6 (New Facilities, General Reduction Requirements), the Best Available Control Technology (BACT) for the, paper machine, identified as EU 029 shall be as follows:

(1) The use of good design and Operating Practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product from the Paper machine shall not exceed 584,000 tons of air dried paper per twelve (12) consecutive month period with compliance determined at the end of the month.

D.5.2 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.5.3 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.5.1 and within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from stack S 029 utilizing methods as approved by the commissioner. This testing shall be done once to demonstrate compliance with the VOC limit. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.5.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.5.1(3) - VOC Best Available Control Technology (BACT), the Permittee shall maintain the monthly records of the throughput of air dried finished product to the paper machine.

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

D.5.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.5.1 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent,

not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activity

(i) One (1) Starch silo, identified as EU 022, permitted in 2014, with a maximum throughput of 2.75 tons of starch per hour and equipped with a baghouse and exhausting to stack S 022.

(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.6.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the starch silo identified as EU 022, shall not exceed 8.07 pounds per hour when operating at a process weight rate of 2.75 tons per hour.

The pounds per hour limitation shall be calculated using the following equation:

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

$E = 4.10\ P^{0.67}$

Where:

E = rate of emission in pounds per hour;
P = process weight rate in tons per hour.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activities

(a) Natural gas-fired combustion sources each with heat input equal to or less than ten million (10,000,000) British thermal units per hour, consisting of six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively identified as EU 011, rated at 39.23 million British thermal units per hour total [326 IAC 2-8-4].

(c) Rotary die cutters, identified as EU 008, installed 1999, 2001 and 2009 [326 IAC 6-3].

(d) Starch silo, equipped with a baghouse, installed in 1999 [326 IAC 6-3].

(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.7.1 Nitrogen Oxides (NOx) [326 IAC 2-3]

The natural gas usage to the six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively identified as EU 011 shall be less than 266.45 million cubic feet of natural gas per twelve (12) consecutive month period, with compliance determined at the end of each month, and the NOx emissions shall not exceed 100 pounds per million cubic feet of natural gas.

Compliance with the above limit in combination with the potential NOx emissions from other emission units will limit the sourcewide NOx emissions to less than 100 tons per year and render the requirements of 326 IAC 2-3 (Emission Offset) not applicable to the entire source.

D.7.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the allowable particulate emission rate from the rotary die cutters, identified as EU 008 and Starch silo shall not exceed the pounds per hour limit as calculated in the following formula:

The pounds per hour limitation shall be calculated using the following equation:

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

$E = 4.10\ P^{0.67}$

Where:
E = rate of emission in pounds per hour;
P = process weight rate in tons per hour.

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

D.7.3 Record Keeping Requirement

(a) To document the compliance status with Condition D.7.1, the Permittee shall maintain records of natural gas usage from the six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively known as EU 011.

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

D.7.4 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.7.1 shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Insignificant Activity

(b) One (1) cold solvent degreaser, identified as EU 007, installed in 1999 [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.8.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

(a) Pursuant to 326 IAC 8-3-2 (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaning degreasers without remote solvent reservoirs constructed after July 1, 1990:

(1) Equip the degreaser with a cover.

(2) Equip the degreaser with a device for draining cleaned parts.

(3) Close the degreaser cover whenever parts are not being handled in the degreaser.

(4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.

(5) Provide a permanent, conspicuous label that lists the operating requirements in (a)(3), (a)(4), (a)(6), and (a)(7) of this condition.

(6) Store waste solvent only in closed containers.

(7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) The Permittee shall ensure the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent used is insoluble in, and heavier than, water.

(C) A refrigerated chiller.

(D) Carbon adsorption.

(E) An alternative system of demonstrated equivalent or better control as those outlined in (b)(1)(A) through (D) of this condition that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:

(A) must be a solid, fluid stream; and

(B) shall be applied at a pressure that does not cause excessive splashing.

D.8.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), before January 1, 2015, the Permittee shall not operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure than 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).

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

D.8.3 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-3-8(c)(2), before January 1, 2015, the following records shall be maintained for each purchase of cold cleaner degreaser solvent:
(1) The name and address of the solvent supplier.
(2) The date of purchase (or invoice/bill dates of contract servicer indicating service date).
(3) The type of solvent purchased.
(4) The total volume of the 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).

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

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) One (1) biogas flare, identified as EU 025, permitted in 2014, with a throughput of 216,000scf of biogas per day (153.9 MMBtu/day) and exhausting to stack S 025.

(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.9.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 127-33729-00094 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the biogas flare, identified as EU 025 shall be as follows:

The GHGs BACT for the Biogas Flare shall be as follows:

(a) Good Design Operating, and Combustion Practices; and

(b) The total CO_2 emissions for Biogas flare shall be limited to less than 3,825 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.9.2 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.9.3 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.9.1(b), the following equation shall be used to determine the CO_2e emissions from the biogas flare, identified as EU 025:

CO_2e emissions (ton/month) = [(Fuel Usage (mmscf/month) x Heat Content (mmbtu/mmscf)) x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu) x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (mmscf/month) = monthly flare fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42, 40 CFR 98 Subpart C or site-specific data, if available

CO_2 EF (114.8 lb/mmbtu for biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CH_4 EF (7.1E-03 lb/mmbtu for biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
N_2O EF (1.4E-03 lb/mmbtu for biogas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CO_2 GWP = 1 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.9.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.1(b) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_2e emissions from the biogas flare.

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

D.9.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.9.1(b) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (HP) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60, Subpart IIII, the fire pump engine is considered new affected sources]

(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.10.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 127-33729-00094 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the emergency fire pump engine identified as EU 027 shall be as follows:

The GHGs BACT for the emergency diesel fire pump engine shall be as follows:

(a) The use of a good engineering design and Fuel Efficient Design;

(b) The use of diesel fuel only; and

(c) The total CO_2 emissions from the fire pump engine shall be limited to less than 19 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

D.10.2 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.10.3 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.10.1(c), the following equation shall be used to determine the CO_2e emissions from the emergency fire pump engine identified as EU 027:

CO_2e emissions (ton/month) = [(Fuel Usage (gal/month) x Heat Content (mmbtu/gal)) x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu) x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (gal/month) = monthly boiler fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42, 40 CFR 98 Subpart C for diesel fuel, or vendor data, if available

CO_2 EF (163.1 lb/mmbtu for diesel fuel) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CH_4 EF (6.6E-03 lb/mmbtu for diesel fuel) = emission factor from GHG MRR (40 CFR 98, Subpart C)
N_2O EF (1.3E-03 lb/mmbtu for diesel fuel) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CO_2 GWP = 1 global warming potential from GHG MRR (40 CFR 98, Subpart A)

CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.10.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.10.1(c) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_2e emissions from the emergency fire pump engine.

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

D.10.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.10.1(c) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) Three (3) natural gas-fired air make up units, identified as EU 030, permitted in 2014, with a combined capacity of 10 MMBtu per hour, exhausting through Stack S030.

(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.11.1 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 127-33729-00094 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired units, identified as EU 030 shall be as follows:

The GHGs BACT for the natural gas-fired units shall be as follows:

(a) Good design operating and Combustion Practices;

(b) The use of only natural gas: and

(c) The total CO_2 emissions for Natural Gas-Fired Units shall be limited to less than 5,125 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

D.11.2 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.11.3 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.11.1(c), the following equation shall be used to determine the CO_2e emissions from the natural gas-fired units, identified as EU 030:

CO_2e emissions (ton/month) = [(Fuel Usage (mmscf/month) x Heat Content (mmbtu/mmscf)) x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu) x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (mmscf/month) = monthly fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42, 40 CFR 98 Subpart C for natural gas, or vendor data, if available

CO_2 EF (117.0 lb/mmbtu for natural gas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CH_4 EF (2.2E-03 lb/mmbtu for natural gas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
N_2O EF (2.2E-04 lb/mmbtu for natural gas) = emission factor from GHG MRR (40 CFR 98, Subpart C)
CO_2 GWP = 1 global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = 21 global warming potential from GHG MRR (40 CFR 98, Subpart A)

N_2O GWP = 310 global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.11.4 Record Keeping Requirements

(a) To document the compliance status with Condition D.11.1(c) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_2e emissions from the natural gas-fired units.

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

D.11.5 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.11.1(c) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 001, installed in 1999, rated at 20.92 million British thermal units per hour, exhausted through Stack S001.

(i) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 013, installed in 2001, rated at 20.92 million British thermal units per hour, exhausted through Stack S002.

(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) Requirements [326 IAC 12][40 CFR 60, Subpart Dc]

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

Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60 Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1 for Boilers EU 001 and EU 013, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

E.1.2 New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, for Boilers EU 001 and EU 013 as specified as follows:

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

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(k) One (1) natural gas fired-boiler, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The boiler will be equipped with a continuous emissions monitoring system (CEMS) for NOx and diluent gas (O_2 or CO_2). [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

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

New Source Performance Standards [326 IAC 12] [40 CFR Part 60, Subpart Db]

E.2.1 General Provisions Relating to NSPS Db [326 IAC 12][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the boiler described in this section except when otherwise specified in 40 CFR Part 60, Subpart Db.

E.2.2 Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [326 IAC 12][40 CFR Part 60, Subpart Db]

The Permittee who operates a steam generating unit that will commence construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 MMBtu/hr) shall comply with the following provisions of 40 CFR Part 60, Subpart Db. The source is subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b
(2) 40 CFR 60.41b
(3) 40 CFR 60.44b(l)(1);
(4) 40 CFR 60.46b(c) and (e);
(5) 40 CFR 60.48b(b),(c),(d),(e) and (f); and
(6) 40 CFR 60.49b(a),(b)(g),(h),(i) and (o).

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(h) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (HP) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60, Subpart IIII, the fire pump engine is considered new affected sources]

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

New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart IIII]

E.3.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the fire pump engine described in this section except when otherwise specified in 40 CFR Part 60, Subpart IIII.

E.3.2 Standards of Performance for Stationary Compression Ingnition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee who owns and operates stationary compression ignition (CI) internal combustion engines (ICE) shall comply with the following provisions of 40 CFR Part 60, Subpart IIII. The source is subject to the following portions of Subpart IIII:

(1) 40 CFR 60.4200(a);
(2) 40 CFR 60.4205(c);
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207(b);
(5) 40 CFR 60.4209(a);
(6) 40 CFR 60.4211(d);
(7) 40 CFR 60.4214(b);
(8) 40 CFR 60.4218;
(9) 40 CFR 60.4219;
(10) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines
(11) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart III.

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

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094

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: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094

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

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

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

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

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

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

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

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

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

Part 70 Quarterly Report

Source Name:	Jet Corr Incorporated
Source Address:	3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.:	T127-33924-00094
Facilities:	Printing and gluing operations, identified as EU 003, EU 004, EU 005, EU 012, EU 018 and EU 019, including the two (2) corrugating machines, identified as EU 006
Parameter:	VOC delivered to the applicators
Limit:	Less than 20.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facilities: Entire Source
Parameter: Single HAP
Limit: Less than ten (10) tons per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facilities: Two (2) boilers, identified as EU 001 and EU 013
Parameter: No. 2 fuel oil
Limit: A total of 350.0 kilogallons per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facilities: Natural gas fired space heaters, including the air makeup units and the unit heaters, identified as EU 011
Parameter: Natural gas Usage
Limit: Less than 266.45 million cubic feet per twelve (12) consecutive month period

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facility: Paper Machine EU 029
Parameter: Air Dried Tons of Finished Product
Limit: shall not exceed 584,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facility: Boiler, EU 028
Parameter: CO2e
Limit: shall not exceed 179,392 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facility: Biogas Flare, EU 025
Parameter: CO2e
Limit: shall not exceed 3,825 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facility: Emergency fire Pump engine, EU 027
Parameter: CO2e
Limit: shall not exceed 19 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

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

Part 70 Quarterly Report

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094
Facility: Natural gas-fired air makeup units EU 030
Parameter: CO2e
Limit: shall not exceed 5,125 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: _____
Title / Position: _____
Signature: _____
Date: _____
Phone: _____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Jet Corr Incorporated
Source Address: 3155 State Road 49, Valparaiso, Indiana 46383
Part 70 Permit No.: T127-33924-00094

Months: _____ to _____ Year: _____

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

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

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attachment A to a Title V Part 70 Operating Permit

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

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Significant Source Modification No.:	**127-33729-00094**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

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

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

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§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]

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§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]

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§60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

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

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

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

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

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

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

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

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

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

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

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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§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]

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

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility.

The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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 $\%R_g$ ($\%R_go$) 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:

$$\%R_go = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

$\%R_go$ = 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.

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§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]

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§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.

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§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]

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§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]

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Attachment B to a Title V Part 70 Operating Permit

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Db] [326 IAC 12]

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Significant Source Modification No.:	**127-33729-00094**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

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

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

§ 60.40b Applicability and delegation of authority.

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

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

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

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

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

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_Xstandards under this subpart and the PM and SO_2standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NO_Xstandards under this subpart and the SO_2standards under subpart J (§60.104).

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

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

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

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

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

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

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

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

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.41b Definitions.

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

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

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

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

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

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

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

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

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

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

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

Dry flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

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

Emerging technology means any SO_2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas means:

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

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

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

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

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

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

Potential sulfur dioxide emission rate means the theoretical SO_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

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

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

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

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

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

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

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2emission control, has a SO_2emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

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

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

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2emission 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_2emission 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_2in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2emission 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_2emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 50 percent of the potential SO_2emission rate (50 percent reduction) and that contain SO_2in excess of the emission limit determined according to the following formula:

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

Where:

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

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

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

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

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

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

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

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

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

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

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

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

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

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2control system is not being operated because of malfunction or maintenance of the SO_2control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

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

§ 60.43b Standard for particulate matter (PM).

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

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

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

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

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

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

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

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

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

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2emissions 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_2emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that

contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.44b Standard for nitrogen oxides (NOX).

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

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50

(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_Xin 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_Xemission limit (expressed as NO_2), ng/J (lb/MMBtu);

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

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

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

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

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

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

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_Xin excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

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

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be

discharged into the atmosphere any gases that contain NO_Xin excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

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

Where:

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

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

H_{go}= Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

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

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

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

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

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

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

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

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

(2) The NO_Xemission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_Xemission limit will be established at the NO_Xemission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_Xemissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific

NO_Xlimit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

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

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

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

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

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

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

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

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

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X(expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

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

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

Where:

E_n= NO_Xemission limit, (lb/MMBtu);

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

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

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

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

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

(a) The SO_2emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2control system maintenance.

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

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2emission rate (% P_s) and the SO_2emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

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

(i) The procedures in Method 19 of appendix A–7 of this part are used to determine the hourly SO_2emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO_2emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

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

Where:

$\%P_s$= Potential SO_2emission rate, percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

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

(i) An adjusted hourly SO_2emission rate (E_{ho}^{o}) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^{o}). The Eho° is computed using the following formula:

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

Where:

E_{ho}^{o} = Adjusted hourly SO_2emission rate, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

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

(ii) To compute the percent of potential SO_2emission rate ($\%P_s$), an adjusted $\%R_g$($\%R_g^{o}$) is computed from the adjusted E_{ao}^{o} from paragraph (b)(3)(i) of this section and an adjusted average SO_2inlet rate (E_{ai}^{o}) using the following formula:

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

To compute E_{ai}^{o} , an adjusted hourly SO_2inlet rate (E_{hi}^{o}) is used. The E_{hi}^{o} is computed using the following formula:

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

Where:

E_{hi}^{o} = Adjusted hourly SO_2inlet rate, ng/J (lb/MMBtu); and

E_{hi}= Hourly SO_2inlet rate, ng/J (lb/MMBtu).

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

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

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2emission 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_2emission 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_2emission 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_2emission 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_2emissions 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_2emission 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_2control 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_2standard 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.

Link to an amendment published at 76 FR 3523, Jan. 20, 2011.

(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_Xemission 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_Xemission 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_2sample 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_2or CO_2measurements 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_Xrequired 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_Xunder §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_Xemission 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_Xemission 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_Xemission 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_Xstandards 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_Xemission 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_Xstandards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_Xemissions 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_Xemission 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_Xemission 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_Xrequired 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_Xshall 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_Xconcentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2concentration.

(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_Xemissions rate at the outlet from the steam generating unit shall constitute the NO_Xemissions 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_Xemission 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_Xemission 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) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

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

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

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

(14) After July 1, 2011, within 90 days after completing a correlation testing run, the owner or operator of an affected facility shall either successfully enter the test data into EPA's WebFIRE data base located at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

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

§ 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_2standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified $SO_2$and O_2or CO_2CEMS 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_2concentration 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_2data 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_2emissions 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_2input rate, or

(2) Measuring SO_2according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2control 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_2measurement 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_2emission 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_2emission 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_2emission 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_2emission 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_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2emissions of the fuel combusted. Alternatively, SO_2span 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_2monitors and for $SO_2$and NO_Xmonitors 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_2monitors and for $SO_2$and NO_Xmonitors 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_Xspan values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2monitoring systems and for NO_Xemission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2(regardless of the SO_2emission level during the RATA), and for $NO_X$when the average NO_Xemission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

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

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

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

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

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

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

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

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

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

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

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

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

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

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

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

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

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

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

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

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

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

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

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

Where:

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

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

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_Xspan 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_Xemission 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_Xemission 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_Xstandards 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_Xemissions.

(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_Xemissions.

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

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

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2or 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_2or PM emissions; or

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.49b Reporting and recordkeeping requirements.

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

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

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

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

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

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

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

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_Xemission rates (*i.e.* , ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.* , the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.* , flue gas O_2level);

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

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality

assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

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

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

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_Xstandards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_Xemission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_Xemission 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_Xemission rates are in excess of the NO_Xemissions 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_Xstandard 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_Xemissions 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_Xemission 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_Xunder §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_2standards 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_2emission 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_2control 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_2emissions 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_2or diluent (O_2or 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_2emission 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_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) is used to determine the overall percent reduction (*i.e.* , $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.* , $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_Xemission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_Xemission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_Xstandard 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_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_Xemission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring* . (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_Xemission limit shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b(i).

(iii) The monitoring of the NO_Xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_Xstandard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions* .

Air ratio control damper is defined as the part of the low NO_Xburner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_Xemission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides* . (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_Xemission limit shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b.

(iii) The monitoring of the NO_Xemission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements* . (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia* . (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”) and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_Xtechnology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_Xemissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$and/or $NO_X$and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_Xstandard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides* . (i) When fossil fuel alone is combusted, the NO_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_Xemission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides* . (i) The NO_Xemissions shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b.

(ii) The monitoring of the NO_Xemissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_Xstandard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for* NO_X. (i) When fossil fuel alone is combusted, the NO_Xemission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_Xemission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for* NO_X. (i) The NO_Xemissions shall be determined by the compliance and performance test methods and procedures for NO_Xin §60.46b.

(ii) The monitoring of the NO_Xemissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements* . (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009]

Attachment C to a Title V Part 70 Operating Permit

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII] [326 IAC 12]

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Significant Source Modification No.:	**127-33729-00094**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.

Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_Xemissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and $NO_X$and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_X$and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i= concentration of NO_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_Xor PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

$\%O_2$= Measured O_2concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent $O_2$and CO_2concentration is measured in lieu of O_2concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and PM gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

$\%CO_2$= Measured CO_2concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an

electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder

and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in

	g/KW-hr (g/HP-hr)			
	Model year(s)	**NO_X+ NMHC**	**CO**	**PM**
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)

	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_Xemissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for NO_Xconcentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_Xconcentration.

			ASTM D 6348–03 (incorporated by reference, see §60.17)	
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63,	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the

			appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same

		engine exhaust at the sampling port location; and		time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per

			cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Part 70 Operating Permit (TITLE V)

Source Description and Location

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Significant Source Modification No.:	**127-33729-00094**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

Public Notice Information

On January 23, 2014, the Office of Air Quality (OAQ) had a notice published in the Chesterton Tribune in Chesterton, Indiana, stating that Jet Corr, Inc had applied for a Part 70 Operating Permit (TITLE V) to continue to operate a stationary corrugated box manufacturing and 100% recycled mill source. The notice also stated that OAQ proposed to issue a Title V permit for this operation and provided information on how the public could review the proposed Title V permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this Title V permit should be issued as proposed.

No changes have been made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the permit that was public noticed. Changes that occur after the public notice are documented in this Addendum to the TSD. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

Comment Received from the Source

On February 17, 2014, Jeff Slayback of TRC Solutions submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

Comment 1: Re: The description of air dried finished product In Condition D.5.1(3) of both permits. The description of production should be 'from' the paper machine.

'The throughput of air dried finished product **from** ~~to~~ the paper machine shall not ….'

Similarly, the conclusion of the VOC BACT analysis in the TSD.

'The throughput of air dried finished product **from** ~~to~~ the paper machine shall not …'

Response 1: The typo in Condition D.5.1(3) - VOC Best Available Control Technology (BACT) has been changed accordingly.

TSD BACT

Step 5: Select BACT

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), IDEM has established the following as BACT for VOC for Paper Machine, identified as EU 029.

(1) The use of good design and Operating Practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product ~~to~~ **from** the Paper machine shall not exceed 584,000 tons per twelve (12) consecutive month period with compliance determined at the end of the month.

Permit

D.5.1 VOC Best Available Control Technology (BACT) [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities, General Reduction Requirements), the Best Available Control Technology (BACT) for the, paper machine, identified as EU 029 shall be as follows:

(1) The use of good design and Operating Practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product ~~to~~ **from** the Paper machine shall not exceed 584,000 tons of air dried paper per twelve (12) consecutive month period with compliance determined at the end of the month.

Technical Support Document (TSD)

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

(e) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The uncontrolled VOC emissions from the paper machine, identified as EU 029 is greater than 25 tons per year. Pursuant to 326 IAC 8-1-6, IDEM has established BACT for VOC for the paper machine, identified as EU 029 as follows:

(1) The use of good design and operating practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product ~~to~~ **from** the Paper machine shall not exceed 584,000 tons per twelve (12) consecutive month period with compliance determined at the end of the month.

Comment 2: Page 4 of 47 in the TSD for T127-33729-00094. The Worst single HAP for the rows 'Boiler EU 028' and 'Total PTE for Nested Source' should be 2.70 instead of 7.5E-04.

Page 5 of 47 in the TSD for T127-33729-00094. The Worst single HAP for the row 'Boiler EU 028' should be 2.70 instead of 7.5E-04, for the row Biogas Flare EU 025 it should be 0.03 instead of 'negl', for the row Insignificant Combustion Units EU 030 it should be 0.08 instead of 'negl', and for the row 'Total PTE for Entire Source' it should be 2.81 instead of 0.001.

Response 2: No changes shall be made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the permit that was public noticed. The Potential to Emit table that appeared on pages 4 and 5 of 47 of the TSD that was public noticed contained few errors in the HAPs emissions for Boiler EU 028, Biogas Flare EU 025 and Insignificant Combustion Units EU 030. IDEM has revised this Potential to Emit table and the revisions are documented below in this Addendum to the Technical Support Document (TSD).

Permit Level Determination – PSD or Emission Offset

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

Process/ Emission Unit	**Potential To Emit of the "Nested" Boiler (tons/year)**									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs	Total HAPs	Worst Single HAP
Boiler EU 028	11.40	7.67	2.50	0.9	6.00	56.73	27.93	179,392	2.84	**2.7** ~~7.5E-04~~
Total PTE for Nested Source	**11.40**	**7.70**	**2.50**	**0.9**	**6.00**	**57.00**	**28.00**	**179,392**	**2.84**	**2.7** ~~**7.5E-04**~~
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e/ 100 mass basis	25	10
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000 CO_2e	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

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*

Process/ Emission Unit	**Potential To Emit of the New Project (tons/year)**									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
New Emission Units										

Process/ Emission Unit	Potential To Emit of the New Project (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179,392	2.84	**2.7** ~~7.5E-04~~
**********	******	********	*****	*****	*****	******	******	******	*****	******
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036	**0.03** ~~negl~~
Diesel Tank EU 026	0	0	0	0	1.5E-4	0	0	0	0	0
Emerg. Gen EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004	negl
Insignificant Combustion EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08	**0.08** ~~nel~~
Total PTE of Entire Source	**18.00**	**14.00**	**9.00**	**1.00**	**77.00**	**61.00**	**34.00**	**188,361**	**2.96**	**2.81** ~~**0.001**~~
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e	25	10
PSD Major Source Thresholds	250	250	250	250	--	250	--	100,000 CO_2e	NA	NA
Emission Offset/ Nonattainment NSR Major Source Thresholds	--	--	--	--	100	--	100	NA	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

Comment 3: Page 8 of 20 in the TSD for T127-33924-00094. The Worst single HAP for the rows 'Boiler EU 028' and 'Total PTE for Nested Source' should be 2.70 instead of 7.5E-04.

Page 9 of 20 in the TSD for T127-33924-00094. The Worst single HAP for the row 'Boiler EU 028' should be 2.70 instead of 7.5E-04, for the row Biogas Flare EU 025 it should be 0.03 instead of 'negl', and for the row Insignificant Combustion Units EU 030 it should be 0.08 instead of 'negl'.

Response 3: No changes shall be made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the permit that was public noticed. The Potential to Emit table that appeared on pages 8 and 9 of 20 of the TSD that was public noticed contained few errors in the HAPs emissions for Boiler EU 028, Biogas Flare EU 025 and Insignificant Combustion Units EU 030. IDEM has revised this Potential to Emit table and the revisions are documented below in this Addendum to the Technical Support Document (TSD).

Potential to Emit After Issuance

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

Process/ Emission Unit	Potential To Emit of the "Nested" Boiler (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs	Total HAPs	Worst Single HAP
Boiler EU 028	11.40	7.67	2.50	0.9	6.00	56.73	27.93	179,392	2.84	**2.7** ~~7.5E-04~~
Total PTE for Nested Source	**11.40**	**7.70**	**2.50**	**0.9**	**6.00**	**57.00**	**28.00**	**179,392**	**2.84**	**2.7** ~~**7.5E-04**~~
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e/ 100 mass basis	25	10
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000 CO_2e	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

****

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
Existing Units										
Other Insignificant Activities	****	****	******	*****	******	*******	******	******	******	*****
New Emission Units										
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179,392	2.84	**2.7** ~~7.5E-04~~
**********	********	****	******	******	******	******	******	********	*******	******
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036	**0.03** ~~negl~~
Diesel Tank EU 026	0	0	0	0	1.5E-4	0	0	0	0	0
Emerg. Gen EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004	negl

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
Insignificant Combustion EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08	**0.08** ~~nel~~
Total PTE of Entire Source	**49**	**46**	**39**	**14**	**99.00**	**90**	**62**	**212,416**	**< 25**	**< 10**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e	25	10
PSD Major Source Thresholds	250	250	250	250	--	250	--	100,000 CO_2e	NA	NA
Emission Offset/ Nonattainment NSR Major Source Thresholds	--	--	--	--	100	--	100	NA	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

Comment 4: Jet Corr is requesting IDEM to added four (4) insignificant storage tanks to the source. Based on current information submitted to IDEM, VOC emissions are not expected from any of the tanks.

Response 4: These four (4) storage tanks have been added to the permit through this addendum to Technical Support Document (ATSD). Since these tanks are not regulated by any rule they will not be added to Section A.3 - Specifically Regulated Insignificant Activities of the permit.

The storage tanks are as follows;

(1) One (1) phosphoric acid storage tank, with capacity of 2,500 gallon. The tank is not regulated by NESHAP.

(2) One (1) ferric chloride storage tank, with capacity of 5,200 gallon. Total HCl emissions are approximately 1 pound per year. The tank is not regulated by NESHAP.

(3) One (1) sodium hydroxide tank, with capacity of 2,500 gallon. The tank is not regulated by NESHAP.

(4) One (1) urea tank, with capacity of 2,500 gallon. The tank is not regulated by NESHAP.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Federally Enforceable State Operating Permit (FESOP) Transitioning to a Part 70 Operating Permit

Source Background and Description

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Significant Source Modification No.:	**127-33729-00094**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

The Office of Air Quality (OAQ) has reviewed the proposed Part 70 operating permit application from Jet Corr, Inc relating to the operation of a corrugated box manufacturing source.

History

On October 2, 2013, Jet Corr, Inc submitted an application to the OAQ requesting a transition to a Title V Part 70 operating permit from their Federally Enforceable State Operating Permit (FESOP), issued on February 10, 2006. An application was submitted by Jet Corr, Inc, relating to the expansion of the Jet Corr, Inc facility by adding a 100% recycled paperboard mill.

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units:

(a) One (1) 3-color 48-inch flexographic printer-folder-gluer machine, identified as EU 003, installed in 1999, capacity: 250 sheets per minute.

(b) One (1) 4-color 48-inch flexographic printer-folder-gluer machine, identified as EU 004, installed in 1999, capacity: 250 sheets per minute.

(c) One (1) 94.5-inch EMBA press, identified as EU 005, installed in 1999, capacity: 957 feet per minute.

(d) One (1) 2-color flexographic printer-folder-gluer machine, identified as EU 012, installed in 2001, capacity: 100 sheets per minute at 89 inches by 205 inches, capacity: 1,708.33 feet per minute line speed.

(e) One (1) flexographic printer-folder-gluer machine, identified as EU 018, installed in 2001, capacity: 79.2 million square inches of paper per hour.

(f) One (1) flexographic model 170 folder gluer machine, identified as EU 019, installed in 2003, capacity: 925 feet per minute line speed.

(g) One (1) baler system, identified as EU 009, installed in 2000, modified in 2003, with a capacity of 6,400 pounds of trimmings per hour, with one (1) identical backup baler to be utilized only in the event of failure of the primary baler unit. The baler system is equipped with a trimmings recovery cyclone and exhausted to Stack S003. As an accepted alternative operating scenario, the cyclone will exhaust to a baghouse and then back into the building.

(h) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 001, installed in 1999, rated at 20.92 million British thermal units per hour, exhausted through Stack S001.

(i) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 013, installed in 2001, rated at 20.92 million British thermal units per hour, exhausted through Stack S002.

(j) One (1) flexographic printer-folder-gluer machine, identified as EU 021, installed in 2006, capacity: 64.2 million square inches of paper per hour.

New Emission Units Permitted in 2014

(k) One (1) natural gas fired-boiler, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The boiler will be equipped with a continuous emissions monitoring system (CEMS) for NOx and diluent (O_2 or CO_2). [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

(l) One (1) paper machine designed to produce linerboard and medium from waste paper, identified as EU 029, permitted in 2014, with a maximum throughput of 1600 tons of air dried finished product per day and exhausting to stack S 029.

Emission Units and Pollution Control Equipment Constructed and/or Operated without a Permit

There are no unpermitted emission units operating at this source during this review process.

Emission Units and Pollution Control Equipment Removed From the Source

No emission units have been removed from this facility through this permitting action.

Insignificant Activities

The source also consists of the following insignificant activities:

(a) Natural gas-fired combustion sources each with heat input equal to or less than ten million (10,000,000) British thermal units per hour, consisting of six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively identified as EU 011, rated at 39.23 million British thermal units per hour total [326 IAC 2-8-4].

(b) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment consisting of miscellaneous cutting torches, identified as EU 010, installed in 1999.

(c) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to one (1) percent by volume, installed in 1999.

(d) On-site fire and emergency response training approved by the department.

(e) One (1) above-ground storage tank, capacity: 1,000 gallons of No. 2 fuel oil, identified as EU 002, installed in 1999.

(f) One (1) cold solvent degreaser, identified as EU 007, installed in 1999 [326 IAC 8-3-2, 326 IAC 8-3-5].

(g) Rotary die cutters, identified as EU 008, installed 1999, 2001 and 2009 [326 IAC 6-3].

(h) One (1) closed loop waste water system, identified as EU 020, installed in 1999.

(i) Starch silo, equipped with a baghouse, installed in 1999 [326 IAC 6-3].

(j) Two (2) paper corrugating machines, identified as EU 006, installed in 2001.

New Insignificant Emission Units Permitted in 2014

(k) One (1) effluent cooling tower, rated with a circulation rate of 500 gpm, identified as EU 023, permitted in 2014.

(l) A waste water treatment plant equalization tank identified as EU 024, permitted in 2014.

(m) One (1) biogas flare, identified as EU 025, permitted in 2014, with a throughput of 216,000scf of biogas per day (153.9 MMBtu/day) and exhausting to stack S 025.

(n) One (1) Emergency fire pump diesel storage tank, identified as EU 026, permitted in 2014, with a nominal capacity of 1000 gallons.

(o) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (HP) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60, Subpart IIII, the fire pump engine is considered new affected source]

(p) Three (3) natural gas-fired air make up units, identified as EU 030, permitted in 2014, with a combined capacity of 10 MMBtu per hour, exhausting through Stack S030.

(q) One (1) Starch silo, identified as EU 022, permitted in 2014, with a maximum throughput of 2.75 tons of starch per hour and equipped with a baghouse and exhausting to stack S 022.

Existing Approvals

Since the issuance of the FESOP 127-19359-00094 on February 10, 2006, transiting to a Title V the source has constructed or has been operating under the following approvals as well:

(a) Administrative Amendment No. 127-24584-00094**,** issued on May 23, 2007;

(b) AA-Permit Term Extension No. 127-25770-00094**,** issued on January 29, 2008; and

(c) Administrative Amendment No. 127-28182-00094**,** issued on July 16, 2009.

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.

Air Pollution Control Justification as an Integral Part of the Process

The following justification was incorporated into this permit from the previous Permit:

(a) The primary purpose of the cyclone is to operate pneumatically, separate trimmings from the air stream and convey the trimmings to the baler.

(b) The baler system cannot operate without the cyclone since the cyclone is the mechanism by which the material is routed to the baler.

(c) The baled trimmings are sold to mills to make paper. Jet Corr, Inc receives approximately $60 per ton which corresponds to a saving of more than $750,000 per year based on the 6,400 pound per hour throughput and their annual hours of operation.

IDEM, OAQ evaluated the above justifications and agreed that the cyclone whose primary purpose is to pneumatically convey trimmings to the baler will be considered as an integral part of the baler system. Therefore, the potential-to-emit PM and PM_{10} will be determined after the cyclone, i.e., the potential-to-emit before and after the cyclone is the same. Operating conditions in the proposed permit will specify that this cyclone shall operate at all times when the baler system is in operation.

Note that even though IDEM OAQ agrees that the cyclone is an integral part of the baler system, the cyclone is still considered a particulate control device. The baghouse, installed in 2003, is not considered, or claimed by Jet Corr, Inc to be, integral to the baler system.

Enforcement Issue

There are no enforcement actions pending.

Emission Calculations

See Appendix A of this document for detailed emission calculations.

County Attainment Status

The source is located in Porter County.

Pollutant	Designation
SO_2	Cannot be classified for the area bounded on the north by Lake Michigan; on the west by the Lake County and Porter County line; on the south by I-80 and I-90; and on the east by the LaPorte County and Porter County line. The remainder of Porter County is better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	On June 11, 2012, the U.S. EPA designated Porter County nonattainment, for the 8-hour ozone standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
Unclassifiable or attainment effective February 6, 2012, for PM2.5.	

(a) Ozone Standards
U.S. EPA, in the Federal Register Notice 77 FR 112 dated June 11, 2012, has designated Porter as nonattainment for ozone. On August 1, 2012, the air pollution

control board issued an emergency rule adopting the U.S. EPA's designation. This rule became effective August 9, 2012. IDEM does not agree with U.S. EPA's designation of nonattainment. IDEM filed a suit against U.S. EPA in the U.S. Court of Appeals for the DC Circuit on July 19, 2012. However, in order to ensure that sources are not potentially liable for a violation of the Clean Air Act, the OAQ is following the U.S. EPA's designation. 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. Therefore, VOC and NO_x emissions were evaluated pursuant to the requirements of Emission Offset, 326 IAC 2-3.

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

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

Fugitive Emissions

(a) This existing source consists of a fossil fuel fired boiler with capacity more than two hundred fifity million (250,000,000) British thermal units per hour heat input, which is one of the 28 source categories, as specified in 326 IAC 2-2-1(ff)(1). The primary operation is not in one of the 28 listed source categories under 326 IAC 2-2 and there is no applicable New Source Performance Standard that was in effect on August 7, 1980. Therefore, fugitive emissions are not counted toward the determination of the PSD applicability from the primary operation at this source.

(b) The fossil fuel fired boilers located at this source are considered as one of the 28 source categories under 326 IAC 2-2 and is considered "nested" within a non-listed source. The potential to emit CO2e from the "nested" source is greater than one hundred (100) tons per year. Therefore, fugitive emissions are counted toward the determination of the PSD applicability from the "nested" source.

Unrestricted Potential Emissions for the New Emission Units

This table reflects the unrestricted potential emissions of the New Emission Units.

Unrestricted Potential Emissions	
Pollutant	Tons/year
PM	18.00
PM_{10}	14.00
$PM_{2.5}$	9.00
SO_2	1.00
VOC	77.00
CO	61.00
NO_x	34.00
GHGs as CO_2e	188,361.00
Pb	0.0008

HAPs	tons/year
Single HAP	< 10
Total HAPs	< 25

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

Unrestricted Potential Emissions for the Source

This table reflects the unrestricted potential emissions of the source.

Pollutant	PTE of Entire Source (Tons/year)
PM	51.00
PM_{10}	47.00
$PM_{2.5}$	40.00
SO_2	104.00
VOC	155.00
CO	90.00
NO_x	82.00
GHGs as CO_2e	236,447
Pb	0.0008

HAPs	tons/year
Single HAP	> 10
Total HAPs	> 25

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

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of SO_2 and VOC are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit.

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

(c) The potential to emit (as defined in 326 IAC 2-7-1(29)) of any single HAP is equal to or greater than ten (10) tons per year. However, the Permittee has agreed to limit the source's single HAP emissions to less than 10 tons per year and make the source an area source of HAPs emission.

Actual Emissions

The following table shows the actual emissions as reported by the source. This information reflects the 2002 OAQ emission data.

Pollutant	Actual Emissions (tons/year)
PM	--
PM_{10}	1
$PM_{2.5}$	1
SO_2	0
VOC	3
CO	7
NO_x	4
Ammonia	0
Pb	0

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

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

Process/ Emission Unit	Potential To Emit of the "Nested" Boiler (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs	Total HAPs	Worst Single HAP
Boiler EU 028	11.40	7.67	2.50	0.9	6.00	56.73	27.93	179,392	2.84	7.5E-04
Total PTE for Nested Source	**11.40**	**7.70**	**2.50**	**0.9**	**6.00**	**57.00**	**28.00**	**179,392**	**2.84**	**7.5E-04**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e/ 100 mass basis	25	10
PSD Major Source Thresholds	100	100	100	100	100	100	100	100,000 CO_2e	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

This nested source consists of a fossil fuel fired boiler with capacity more than two hundred fifity million (250,000,000) British thermal units per hour heat input, which is one of the 28 source categories, as specified in 326 IAC 2-2-1(ff)(1). Therefore, PSD threshold for all regulated pollutants are determined at one hundred (100) tons per year. The potential to emit CO2e is greater than one hundred thousand (100,000) tons per year and one hundred (100) tons per year mass basis. Therefore, the CO2e of the nested fossil fuel fired boiler exceed the major source threshold and is therefore subject to the requirements of 326 IAC 2-2 (PSD).

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
Existing Units										
Machines EU 003 & 004	0	0	0	0	20.00	0	0	0	< 25	< 10
EMBA Press EU 005	0	0	0	0		0	0	0		
Machine EU 012	0	0	0	0		0	0	0		
Machine EU 018	0	0	0	0		0	0	0		
Machine EU 019	0	0	0	0		0	0	0		
Machine EU 021	0	0	0	0		0	0	0		
Two (2) Paper Corrugating Machines EU 006	0	0	0	0		0	0	0		
Baler System EU 009	28	28	28	0	0	0	0	0	0	0
Two (2) Boilers EU 001 & 013	0.65	1.5	1.5	12.5	0.99	15	11.3	3951	0.003	0.003
Combustion Units EU 011	0.3	1.3	1.3	0.1	0.9	14.2	16.8	20,338	0.32	0.32
Other Insignificant Activities	2	1	0	0	0.1	0	0	0	0	0
New Emission Units										
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179,392	2.84	7.5E-04
Paper Machine EU 029	0	0	0	0	70.31	0	0	0	0	0
Starch Silo EU 022	2.95	2.95	2.95	0	0	0	0	0	0	0
Cooling Tower EU 023	2.5	2.5	2.5	0	6E-05	0	0	0	6.0E-5	6.0E-5
EQ Tank EU 024	0	0	0	0	1.4E-5	0	0	0	1.4E-5	1.4E-5
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036	negl
Diesel Tank EU 026	0	0	0	0	1.5E-4	0	0	0	0	0
Emerg. Gen EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004	negl
Insignificant Combustion EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08	nel

Process/ Emission Unit	Potential To Emit of the Entire Source After Issuance (tons/year)									
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	GHGs as CO2e	Total HAPs	Worst Single HAP
Total PTE of Entire Source	**49**	**46**	**39**	**14**	**99.00**	**90**	**62**	**212,416**	**< 25**	**< 10**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100,000 CO_2e	25	10
PSD Major Source Thresholds	250	250	250	250	--	250	--	100,000 CO_2e	NA	NA
Emission Offset/ Nonattainment NSR Major Source Thresholds	--	--	--	--	100	--	100	NA	NA	NA

negl. = negligible
* Under the Part 70 Permit program (40 CFR 70), PM10 and PM2.5, not particulate matter (PM), are each considered as a regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

(a) This entire stationary source is not major for PSD because the major activities at the source are paper production and emissions of each regulated pollutant, excluding GHGs, are less than two hundred fifty (<250) tons per year and it is not in one of the twenty-eight (28) listed source categories.

(b) This existing stationary source is not major for Emission Offset because the emissions of the nonattainment pollutant, VOC and NOx are less than one hundred (<100) tons per year.

Federal Rule Applicability

(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 PTE of emissions from these emission units are less than the threshold of 100 tons per year. Therefore, Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any of the emission units at this source.

(b) The requirements of Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units 40 CFR 60, Subpart Dc are applicable to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). The boiler, identified as EU 001 and EU 013 are subject to this rule because the boilers have

a heat input capacity greater than10 MMBtu/hr, each. The emission units subject to this rule are as follows;

(A) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 001, installed in 1999, rated at 20.92 million British thermal units per hour, exhausted through Stack S001.

(B) One (1) natural gas-fired low NO_X boiler with No. 2 fuel oil as backup, identified as EU 013, installed in 2001, rated at 20.92 million British thermal units per hour, exhausted through Stack S002.

These boilers are subject to the following portions of Subpart Dc.

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

(c) The boiler, identified as EU 028 is subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for Industrial - Commercial Institutional Steam Generating Unit, which is incorporated by reference as 326 IAC 12 because they are boilers that will commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)). The boiler, identified as EU 028 has a heat input capacity greater than 100 MMBtu/hr. The specific facilities subject to this rule includes the following.

(A) One (1) natural gas fired-boilers, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The stacks have continuous emissions monitors (CEMS) for NOx and either O_2 or CO_2. [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

The boiler is subject to the following portions of Subpart Db:

(1) 40 CFR 60.40b
(2) 40 CFR 60.41b
(3) 40 CFR 60.44b(l)(1);
(4) 40 CFR 60.46b(c) and (e);
(5) 40 CFR 60.48b(b),(c),(d),(e) and (f);
(6) 40 CFR 60.49b(a),(b)(g),(h),(i) and (o);

(d) The emergency diesel fire pump engine, identified as EU 027 is subject to the requirements of 40 CFR, Subpart IIII - Standard of Performance for Stationary Compression Ignition Internal Combustion Engines because the emergency diesel fire pump engine will be constructed after July 11, 2005 and manufactured after April 1, 2006. The specific facilities subject to this rule includes the following.

(A) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (ph) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60, Subpart IIII, the fire pump engine is considered new affected source]

The emergency diesel fire pump engine is subject to the following sections of 40 CFR Part 60, Subpart IIII.

(1) 40 CFR 60.4200(a);
(2) 40 CFR 60.4205(c);
(3) 40 CFR 60.4206;
(4) 40 CFR 60.4207(b);
(5) 40 CFR 60.4209(a);
(6) 40 CFR 60.4211(d);
(7) 40 CFR 60.4214(b);
(8) 40 CFR 60.4218;
(9) 40 CFR 60.4219;
(10) Table 4 to Subpart IIII of Part 60 - Emission Standard for Stationary Fire Pump Engines
(11) Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart III.

(e) The requirements of Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing, 40 CFR 60.430, Subpart QQ are not included in the permit for any of the printer-folder-gluer machines since the machines are all flexographic rather than rotogravure equipment.

(f) The requirements of Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations, 40 CFR 60.440, Subpart RR are not included in the permit for any of the printer-folder-gluer machines since these facilities do not manufacture pressure sensitive tapes or labels.

(g) The requirements of the New Source Performance Standard, 326 IAC 12 (40 CFR 60 Subpart Kb) are not included in the permit for the above-ground, 1,000 gallon, No. 2 fuel oil storage tank, identified as EU 002, constructed after July 23, 1984 because the capacity of this tank is less than 75 cubic meters and was installed in 1999.

(h) The requirements of National Emission Standards for Hazardous Air Pollutants (NESHAP) for the Printing and Publishing Industry, 40 CFR 63.820, Subpart KK are not included in the permit because the source is an area source of HAPs.

(i) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63.7480, Subpart DDDDD are not included in the permit for this source. The source is not a major source of HAPs, therefore, the requirements of Subpart DDDDD are not included in the permit for this source.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Halogenated Solvent Cleaning, 40 CFR Part 63.460, Subpart T, are not included in the permit for the insignificant degreasing operation, because this operation does not use a halogenated solvent as specified in 40 CFR Part 63, Subpart T.

(k) The requirements of Area Source MACT - National Emission Standards for Hazardous Air Pollutants – Industrial, Commercial, and Institutional Boilers at Area Sources 40 CFR Part 63 Subpart JJJJJJ regulates HAP emissions from industrial, commercial, and institutional boilers at area sources of HAP. This requirements establishes national emission limitations and work practice standards for HAPs emitted from industrial, commercial, and institutional boilers located at area sources of HAP. Pursuant to 40 CFR 63.11195(e), the gas-fired boiler, identified as EU 028 is exempt from this rule.

(l) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAPs) (326 IAC 20 and 40 CFR Part 63 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. The diesel generator associated with the emergency fire pump is subject to NSPS, therefore, pursuant to 40 CFR 63.6593(c), the generator is not subject to any requirements under Subpart ZZZZ.

State Rule Applicability - Entire Source

326 IAC 1-6-3 (Preventive Maintenance Plan)
The source is subject to 326 IAC 1-6-3.

326 IAC 2-2 (Prevention of Significant Deterioration)
This existing stationary source is not one of the 28 listed source categories and the unrestricted potential to emit of each regulated pollutant is less than 250 tons per year. Therefore, this source is a not major source pursuant to 326 IAC 2-2 (PSD). But this source will now consist of a fossil fuel fired boiler with capacity more than two hundred fifity million (250,000,000) British thermal units per hour heat input, which is one of the 28 source categories, as specified in 326 IAC 2-2-1(ff)(1). Based on PSD guidance for "nesting activities," these operations will be nested for the PSD applicability determination. Therefore, the nested fossil fuel fired boiler is a major stationary source, under PSD (326 IAC 2-2), because the potential to emit CO2e is greater than one hundred thousand (100,000) tons per year and one hundred (100) tons per year on mass basis. The project has potential to emit CO2e greater than 100,000 tons per year of CO2e and two hundred and fifty (250) tons per year on mass basis, therefore the project is subject to the requirements of 326 IAC 2-2 (PSD).

326 IAC 2-3 (Emission Offset)

(a) Pursuant to AAF 127-14213 issued June 28, 2001, low NO_X burners shall be required on the source's boilers. The No. 2 fuel oil usage of the to the two (2) boilers, identified as EU 001 and EU 013 shall be limited to less than 350 kilo gallons per twelve (12) consecutive month period, with compliance determined at the end of each month, and the revised NOx emissions shall not exceed 20 pounds per kilo gallons of No. 2 fuel oil.

Compliance with the above limits in combination with the potential NOx emissions from other emission units will limit the sourcewide NOx emissions to less than 100 tons per year and render the requirements of 326 IAC 2-3 (Emission Offset) not applicable to the entire source.

(b) The natural gas usage of the six (6) natural gas-fired makeup air units and eighteen (18) natural gas-fired unit heaters, collectively identified as EU 011 shall be less than 266.45 million cubic feet of natural gas per twelve (12) consecutive month period, with compliance determined at the end of each month, and the NOx emissions shall not exceed 100 pounds per million cubic feet of natural gas.

Compliance with the above limit in combination with the potential NOx emissions from other emission units will limit the sourcewide NOx emissions to less than 100 tons per year and render the requirements of 326 IAC 2-3 (Emission Offset) not applicable to the entire source.

(c) The VOC emissions has been revised in this permit No T127-33729-00094. The total VOC delivered to the printing and gluing operations, shall be limited to less than 20.0 tons of VOC per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with this limit will limit the VOC emissions from the printing and gluing operations and other emission units to less than 25 tons per year and render the requirements of 326 IAC 2-3 (Emission Offset) not applicable to the entire source.

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T127-33729-00094 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the source shall be as follows:

The GHGs BACT for the Natural Gas-Fired Boiler, identified as EU 028 shall be as follows;

(a) The use of natural gas and biogas only,

(b) Implementation of an energy efficient design

(c) Good operating and combustion practices;

(d) Boiler designed for 74% thermal efficiency (HHV);

(e) The emission rate shall not exceed 117 lbs CO2 per MMBtu/hour; and

(f) The total CO_2 emissions from the natural gas-fired boiler shall not exceed 179,392 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

The GHGs BACT for the Biogas Flare, identified as EU 025 shall be as follows;

(a) Good Design Operating, and Combustion Practices; and

(b) The total CO_2 emissions for Biogas flare shall be limited to less than 3,825 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

The GHGs BACT for the Emergency Fire Pump Engine identified as EU 027 shall be as follows;

(a) The use of a good engineering design and Fuel Efficient Design;

(b) The use of diesel fuel only; and

(c) The total CO_2 emissions from the fire pump engine shall be limited to less than 19 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

The GHGs BACT for the Natural Gas-Fired Units, identified as EU 030 shall be as follows;

(a) Good design operating and Combustion Practices;

(b) The use of only natural gas: and

(c) The total CO_2 emissions for Natural Gas-Fired Units shall be limited to less than 5,125 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Hazardous Air Pollutants Minor Limits
The single Hazardous Air Pollutant (HAP) delivered to the printing and gluing operations, shall be limited to less than ten (10) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with the above limit and the potential HAPs emissions from the other emission units will limit the source-wide HAPs emission to less than ten (10) tons per year of a single HAP and less than twenty-five (25) tons per year of a combination of HAPs and make the source an area source of HAPs.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of these new emission units in the plant (new recycle Mill) will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 1-7 (Actual Stack Height Provisions)
The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO_2 or PM emissions in levels greater than 25 tons per year. The boiler stacks, are subject to these requirements. As such, these stacks are subject to the height provisions listed in 326 IAC 1-7-3, which prohibits excessive concentrations of PM and SO_2 emissions.

326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is located in Porter County and its emissions of VOC or NOx are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted by July 1, 2014 and every year 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(1)

326 IAC 6.5 PM Limitations Except Lake County
This source is not subject to 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

326 IAC 6.8 PM Limitations for Lake County
This source is not subject to 326 IAC 6.5 because it is not located in Lake County.

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

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is not subject to the requirements of 326 IAC 6-5 because the amounts of fugitive particulate matter emissions from unpaved and paved roadways are less than 25 tons per year.

State Rule Applicability – Individual Facilities

326 IAC 3-5 (Continuous Monitoring of Emissions)
The natural gas-fired boiler, identified as EU 028 is subject to the monitoring requirements of 326 IAC 3-5. In order to comply with the NSPS requirements under 40 CFR 60.48b, the source will install a CEMS system on EU 028 to monitor NOx and either O_2 or CO_2.

Pursuant to 326 IAC 3-5-1(b)(2)(C) and 326 IAC 3-5-1(a)(1), a continuous monitoring system shall be installed, calibrated, operate and maintain Nitrogen Oxide (NOx) and O_2 or CO_2 for each of the stacks, S 028A and B in accordance with 326 IAC 3-5-2 and 326 IAC 3-5-3.

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)

(a) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boilers, identified as EU 001 and EU 013 shall not exceed 0.413 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 41.84 MMBtu/hr.

(b) Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the boiler, identified as EU 028 shall not exceed 0.23 pounds per million Btu heat input (lb/MMBtu). This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 391.84 MMBtu/hr.

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

(a) Pursuant 326 IAC 6-3-1(b)(14), the two (2) paper corrugating machines do not emit particulate and therefore are exempt from the requirements of 326 IAC 6-3.

(b) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the starch silo, shall not exceed the pounds per hour rate established by the following formula.

The pound per hour limitation was calculated with the following equation:

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

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

(c) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the rotary die cutters, identified as EU 008, shall not exceed the pounds per hour rate established by the following formula.

The pound per hour limitation was calculated with the following equation:

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

$E = 4.10\ P^{0.67}$

Where:

E = rate of emission in pounds per hour and

P = process weight rate in tons per hour

(d) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the baler system identified as EU 009, shall not exceed 8.94 pounds per hour when operating at a process weight rate of 3.2 tons per hour (6400 lbs per hr).

The cyclone, which has been determined to be an integral part of this emission unit, as well as the baghouse installed in 2003, shall be in operation at all times the baler system is in operation, in order to comply with this limit.

(e) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the starch silo identified as EU 022, shall not exceed 8.07 pounds per hour when operating at a process weight rate of 2.75 tons per hour.

The pound per hour limitation was calculated with the following equation:

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

$E = 4.10\ P^{0.67}$

Where;

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations

(a) The boilers, identified as EU 001 and EU 013 are subject to 326 IAC 7-1.1 because its SO_2 PTE is equal to or greater than 25 tons per year. Therefore, pursuant to 326 IAC 7-1.1-2(a)(3), when burning No. 2 fuel oil, the SO_2 emissions from boilers, identified as EU 001 and EU 013, shall not exceed 0.5 pounds per million British thermal units of heat input.

(b) The potential to emit SO_2 emissions from the natural gas-fired boiler, identified as EU 028 is less than 25 tons per year. Therefore, this unit is not subject to the requirements of 326 IAC 7-1.1.

(c) The potential to emit SO_2 emissions from the biogas flare, identified as EU 025 is less than 25 tons per year. Therefore, this unit is not subject to the requirements of 326 IAC 7-1.

(d) The potential to emit SO_2 emissions from the emergency diesel fire pump engine identified as EU 027 is less than 25 tons per year. Therefore, this unit is not subject to the requirements of 326 IAC 7-1.

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

(a) The natural gas-fired boiler, identified as EU 028 was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to this boiler.

(b) The biogas flare identified as EU 025 was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons per year, each. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to the biogas flare.

(c) The emergency diesel fire pump engine, identified as EU 027 was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons per year. Therefore,

the requirements of 326 IAC 8-1-6 (BACT) are not applicable to the emergency fire pump engine.

(d) The natural gas-fired units, identified as EU 030 were constructed after January 1, 1980 and have potential VOC emissions less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to these natural gas-fired units.

(e) This rule requires that new facilities (as of January 1, 1980), which have potential VOC emissions of 25 tons or more per year, located anywhere in the state, which are not otherwise regulated by other provisions of 326 IAC 8, shall reduce VOC emissions using Best Available Control Technology (BACT). The uncontrolled VOC emissions from the paper machine, identified as EU 029 is greater than 25 tons per year. Pursuant to 326 IAC 8-1-6, IDEM has established BACT for VOC for the paper machine, identified as EU 029 as follows:

(1) The use of good design and operating practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product to the Paper machine shall not exceed 584,000 tons per twelve (12) consecutive month period with compliance determined at the end of the month.

326 IAC 8-5-5 (Graphic Arts Operations)
The flexographic printers, identified as EU 003, EU 004, EU 012, EU 018, EU 019, EU 019 EU 021 and EMBA Press, identified as EU 005 are subject to 326 IAC 8-5-5 because they were constructed after 1980 and the source has potential VOC emissions greater than 25 tons per year. Pursuant to this rule, no owner or operator of a facility subject to this section and employing solvent-containing ink may cause, allow, or permit the operation of the facility unless:

(a) The volatile fraction of the ink, as it is applied to the substrate, contains twenty-five percent (25%) by volume or less of VOC, and seventy-five percent (75%) by volume or more of water; or

(b) The ink as it is applied to the substrate, less water, contains sixty percent (60%) by volume or more of nonvolatile material; and

(c) The ink, as applied to the substrate, meets an emission limit of 0.5 pounds of VOC per pound of solids in the ink.

The source shall comply with the VOC content limitations specified above by either using compliant coatings at flexographic printers, identified as EU 003, EU 004, EU 012, EU 018, EU 019, EU 019 EU 021 and EMBA Press, identified as EU 005.

Pursuant to 326 IAC 8-5-5(f), work practices for flexographic printers, identified as EU 003, EU 004, EU 012, EU 018, EU 019, EU 019 EU 021 and EMBA Press, identified as EU 005 shall include, but not be limited to, the following:

(a) When not in use, all cleaning materials shall be kept in closed containers.

(b) Cleaning materials shall be conveyed from one (1) location to another in closed containers or pipes.

326 IAC 8-3-2 (Cold Cleaner Operations)
The cold cleaning operations are subject to 326 IAC 8-3-2 (Cold Cleaner Operations). This rule applies to cold cleaner type degreasing facilities constructed after July 1, 1990.

326 IAC 8-3-8 (Material requirements for cold cleaning degreasers)
This source is subject to the provisions of 326 IAC 8-3-8 (Material requirements for cold cleaning degreasers) because the source is a user of solvents for use in cold cleaning degreasers. The source shall meet the material requirements for cold cleaning degreasers specified in 326 IAC 8-3-8(c) and record keeping requirements specified in 326 IAC 8-3-8(d) of this rule.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
This source is not subject to 326 IAC 9-1 though it is a stationary source of CO emissions that commenced operation after March 21, 1972 but has CO emissions of less than 100 tons per year.

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 and monitoring requirements applicable to this source are as follows;

Testing Requirements

(a) Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
Boiler (EU 028)	No Control	60 days / no later than 180 days	Thermal Efficiency	One time testing	326 IAC 2-2-3
Paper Machine (EU 029)	No Control	60 days / no later than 180 days	VOC	One time testing	326 IAC 8-1-6

(b) The compliance monitoring requirements applicable to this source are as follows:

Equipments	Parameter	Frequency	Range	Excursions and Exceedances	Limit or Requirement
Two (2) Natural Gas-Fired Boilers (EU 001 and 013)	Visible Emissions	Daily	Normal-Abnormal	Response Steps	326 IAC 6-2-4
Baler System (Cyclone)	Visible Emissions	Daily	Normal-Abnormal	Response Steps	326 IAC 6-3-2

(c) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Value	Excursions and Exceedances	Requirement
Boiler EU 028 (Low NOx Burner, with FGD)	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	NA
Boiler EU 028 (Low NOx Burner, with FGD)	O_2 or CO_2 CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	NA

Recommendation

The staff recommends to the Commissioner that the Part 70 Operating Permit be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on October 2, 2013.

Conclusion

The operation of this corrugated box manufacturing source shall be subject to the conditions of the attached Part 70 Operating Permit No. 127-33729-00094.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

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

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

Appendix A: Emissions Calculations
Emission Summary
Source Name: Jet Corr, Inc.
Source Location: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Permit Reviewer: Josiah Balogun
Date: 12-Nov-13

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179392.29	2.84
Paper Machine EU 029	0	0	0	0	70.31	0	0	0	0
Starch Silo EU 022	2.95	2.95	2.95	0	0	0	0	0	0
Cooling Tower EU 023	2.5	2.5	2.5	0	0.00006	0	0	0	0.00006
EQ Tank EU 024	0	0	0	0	0.000014	0	0	0	0.000014
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036
Diesel Tank EU 026	0	0	0	0	0.00015	0	0	0	0
Emergency Fire Pump EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004
insignificant Combustion Units EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08
Total Emissions	17.74	13.96	8.54	1.04	76.97	60.52	33.92	188361.33	2.96

Appendix A: Emissions Calculations
Emission Summary
Source Name: Jet Corr, Inc.
Source Location: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Permit Reviewer: Josiah Balogun
Date: 12-Nov-13

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179392.29	2.84
Paper Machine EU 029	0	0	0	0	70.31	0	0	0	0
Starch Silo EU 022	2.95	2.95	2.95	0	0	0	0	0	0
Cooling Tower EU 023	2.5	2.5	2.5	0	0.00006	0	0	0	0.00006
EQ Tank EU 024	0	0	0	0	0.000014	0	0	0	0.000014
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036
Diesel Tank EU 026	0	0	0	0	0.00015	0	0	0	0
Emergency Fire Pump EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004
insignificant Combustion Units EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08
Total Emissions	17.74	13.96	8.54	1.04	76.97	60.52	33.92	188361.33	2.96

Appendix A: Emissions Calculations
Emission Summary
Source Name: Jet Corr, Inc.
Source Location: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Permit Reviewer: Josiah Balogun
Date: 12-Nov-13

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Existing Units									
Machines EU 003 and 004	0	0	0	0	26.8	0	0	0	17.64
EMBA Press EU 005	0	0	0	0	8.56	0	0	0	4.28
Machine EU 012	0	0	0	0	9.33	0	0	0	4.46
Machine EU 018	0	0	0	0	6.95	0	0	0	0.52
Machine EU 019	0	0	0	0	8.27	0	0	0	4.13
Machine EU 021	0	0	0	0	5.63	0	0	0	0.42
Baler System EU 009	28	28	28	0	0	0	0	0	0
Two (2) Boiler EU 001&013	2.6	3	2	102.8	1	15.1	31.4	29982	0.34
Combustion Units EU 011	0.3	1.3	1.3	0.1	0.9	14.2	16.8	20104	0.32
Two (2) Paper Corrugating Machines EU 006	0	0	0	0	10.1	0	0	0	0.016
Other insignificant Units	2	1	0	0	0.1	0	0	0	0
New Emission Units									
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179392.29	2.84
Paper Machine EU 029	0	0	0	0	70.31	0	0	0	0
Starch Silo EU 022	2.95	2.95	2.95	0	0	0	0	0	0
Cooling Tower EU 023	2.5	2.5	2.5	0	0.00006	0	0	0	0.00006
EQ Tank EU 024	0	0	0	0	0.000014	0	0	0	0.000014
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036
Diesel Tank EU 026	0	0	0	0	0.00015	0	0	0	0
Emergency Fire Pump EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004
insignificant Combustion Units EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08
Total Emissions	51	47	40	104	155	90	82	238447	35

Appendix A: Emissions Calculations
Emission Summary
Source Name: Jet Corr, Inc.
Source Location: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Permit Reviewer: Josiah Balogun
Date: 12-Nov-13

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Emission Unit									
Existing Units									
Machines EU 003 and 004	0	0	0	0		0	0	0	
EMBA Press EU 005	0	0	0	0		0	0	0	
Machine EU 012	0	0	0	0		0	0	0	
Machine EU 018	0	0	0	0	20	0	0	0	Single HAP < 10
Machine EU 019	0	0	0	0		0	0	0	
Machine EU 021	0	0	0	0		0	0	0	
Two (2) Paper Corrugating Machines EU 006	0	0	0	0		0	0	0	
Baler System EU 009	28	28	28	0	0	0	0	0	0
Two (2) Boiler EU 001&013*	0.65	1.5	1.5	12.5	0.99	15	11.3	3951	0.003
Combustion Units EU 011	0.3	1.3	1.3	0.1	0.9	14.2	16.8	20104	0.32
Other insignificant Units	2	1	0	0	0.1	0	0	0	0
New Emission Units									
Boiler EU 028	11.42	7.67	2.51	0.9	6.13	56.73	27.93	179392.29	2.84
Paper Machine EU 029	0	0	0	0	70.31	0	0	0	0
Starch Silo EU 022	2.95	2.95	2.95	0	0	0	0	0	0
Cooling Tower EU 023	2.5	2.5	2.5	0	0.00006	0	0	0	0.00006
EQ Tank EU 024	0	0	0	0	0.000014	0	0	0	0.000014
Biogas Flare EU 025	0.5	0.47	0.47	0.08	0.25	0.07	1.18	3825	0.036
Diesel Tank EU 026	0	0	0	0	0.00015	0	0	0	0
Emergency Fire Pump EU 027	0.04	0.04	0.04	0.03	0.04	0.11	0.51	19.04	0.0004
insignificant Combustion Units EU 030	0.33	0.33	0.07	0.03	0.24	3.61	4.3	5125	0.08
Total Emissions	49	46	39	14	99.0	90	62	212416	Single HAP <10 Combined HAPs < 25

Table 1: Summary of Potential to Emit for New Recycle Mill

Pollutant	Boiler	Paper Machine	Starch Silo	Cooling Tower	EQ Tank	Flare	Diesel Tank	Emergency Fire Pump	Misc. NG Units	Total	PSD Significance Threshold (326 IAC 2-2-1(ww))
	EU 028	EU 029	EU 022	EU 023	EU 024	EU 025	EU 026	EU 027	EU 030		
	tons per year										
PM	11.42	-	2.95	2.50	-	0.50	-	0.04	0.33	**17.74**	25
PM10	7.67	-	2.95	2.50	-	0.47	-	0.04	0.33	**13.95**	15
PM2.5	2.51	-	2.95	2.50	-	0.47	-	0.04	0.07	**8.54**	10*
SO2	0.90	-	-	-	-	0.08	-	0.03	0.03	**1.04**	40
CO	56.73	-	-	-	-	0.07	-	0.11	3.61	**60.52**	100
NOX	27.93	-	-	-	-	1.18	-	0.51	4.29	**33.92**	40
VOC	6.13	70.31	-	6.04E-05	1.38E-05	0.25	1.45E-04	0.04	0.24	**76.97**	**40**
CO2e	179,392	-	-	-	-	3,825	-	19.04	5,125	**188,361**	**75,000**
Lead	7.52E-04	-	-	-	-		-		2.15E-05	**7.73E-04**	0.60

**and 40 TPY SO2, 40 TPY NOx*

Insignificant Activity Thresholds per 326 IAC 2-7-1(21)(E)

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
lb/hr		5	5		3	5	5			
lb/day		25	25	25	15	25	25	3.29	5	12.5
tpy	5	5	5	25	10	10	10	0.2	1	2.5

EU 028 Boiler PTE

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	2.61	1.75	0.57	12.95	1.40	6.38	0.21	1.72E-04	0.62	0.00
Over Threshold?		No	No		No	**Yes**	No			
Emissions (lb/day)	62.60	42.01	13.78	310.84	33.60	153.02	4.94	0.00	14.83	0.00
Over Threshold?		**Yes**	No	**Yes**	**Yes**	**Yes**	No	No	**Yes**	No
Emissions (tpy)	11.42	7.67	2.51	56.73	6.13	27.93	0.90	7.52E-04	2.71	0.00
Over Threshold?	**Yes**	**Yes**	No	**Yes**	No	**Yes**	No	No	**Yes**	No
Conclusion:	**Does not meet requirements for insignificant activities.**									

EU 029 Paper Machine PTE

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	-	-	-	-	16.05	-	-	-	-	-
Over Threshold?		No	No		**Yes**	No	No			
Emissions (lb/day)	-	-	-	-	385.28	-	-	-	-	-
Over Threshold?		No	No	No	**Yes**	No	No	No	No	No
Emissions (tpy)	-	-	-	-	70.31	-	-	-	-	-
Over Threshold?	No	No	No	No	**Yes**	No	No	No	No	No
Conclusion:	**Does not meet requirements for insignificant activities.**									

EU 022 Starch Silo

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	0.67	0.674	0.6737	-	-	-	-	-	-	-
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	16.17	16.17	16.17	-	-	-	-	-	-	-
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	2.95	2.95	2.95	-	-	-	-	-	-	-
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.)									

EU 023 Effluent Cooling Tower

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	0.57	0.57	0.57	-	1.38E-05	-	-	-	1.28E-05	0.00E+00
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	13.68	13.68	13.68	-	3.31E-04	-	-	-	3.08E-04	0.00E+00
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	2.50	2.50	2.50	-	6.04E-05	-	-	-	5.62E-05	0.00E+00
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.)* and falls under 326 IAC 2-7-1(21)(J)(ix)(FF)(bb)									

**Unit is potentially subject to NESHAP and would therefore not qualify for an insignificant activiry by emissions but would still fall under (21)(J)(ix)(FF)(bb)*

EU 024 EQ Tank

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	-	-	-	-	3.14E-06	-	-	-	3.12E-06	0.00E+00
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	-	-	-	-	7.54E-05	-	-	-	7.49E-05	0.00E+00
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	-	-	-	-	1.38E-05	-	-	-	1.37E-05	0.00E+00
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.)									

EU 025 Biogas Flare

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	0.11	0.11	0.11	0.02	0.06	0.27	0.02	-	5.81E-03	0.00E+00
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	2.75	2.59	2.59	0.39	1.36	6.48	0.43	-	1.39E-01	0.00E+00
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	0.50	0.47	0.47	0.07	0.25	1.18	0.08	-	2.54E-02	0.00E+00
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.)									

EU 026 Diesel Tank

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	-	-	-	-	0.10	-	-	-	-	-
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	-	-	-	-	2.40	-	-	-	-	-
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	-	-	-	-	1.45E-04	-	-	-	-	-
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	**This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.) and falls under 326 IAC 2-7-1(21)(J)(iii)(AA)**									

EU 027 Emergency Fire Pump

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	0.14	0.14	0.14	0.44	0.17	2.05	0.14	-	5.49E-04	0.00E+00
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	3.46	3.46	3.46	10.62	4.02	49.28	3.24	-	1.32E-02	0.00E+00
Over Threshold?		No	No	No	No	**Yes**	No	No	No	No
Emissions (tpy)	0.04	0.04	0.04	0.11	0.04	0.51	0.03	-	1.37E-04	0.00E+00
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	**This unit does not meet insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.)(v), however it does fall under 326 IAC 2-7-1(21)(J)(xxii)(CC)**									

EU 030 Misc. NG Units

	PM	PM10	PM2.5	CO	VOC	Nox	SO2	Lead	Single HAP	Combined HAPs
Emissions (lb/hr)	0.07	0.07	0.02	0.82	0.05	0.98	0.01	4.90E-06	1.76E-02	0.00E+00
Over Threshold?		No	No		No	No	No			
Emissions (lb/day)	1.79	1.79	0.39	19.76	1.29	23.53	0.14	1.18E-04	4.24E-01	0.00
Over Threshold?		No	No	No	No	No	No	No	No	No
Emissions (tpy)	0.33	0.33	0.07	3.61	0.24	4.29	0.03	2.15E-05	7.73E-02	0.00E+00
Over Threshold?	No	No	No	No	No	No	No	No	No	No
Conclusion:	**This unit meets insignificant activity emissions thresholds per 326 IAC 2-7-1(21)(E.) and falls under 326 IAC 2-7-1(21)(J)(i)(AA)(aa)**									

	EU 028 Boiler				EU 023 Cooling Tower				EU 024 EQ Tank			
	Fuel Usage	3006.31	MMCF/yr		Throughput	262,800,000	gal/yr					
		0.34	MMCF/hr			30,000	gal/hr					
HAP	EF (lb/MMCF)	lb/hr	lb/day	lb/yr	EF (lb/gal)	lb/hr	lb/day	lb/yr	EF (lb/hr)	lb/hr	lb/day	lb/yr
1,3 Butadiene												
Acetaldehyde												
Arsenic	2.00E-04	6.86E-05	1.65E-03	6.01E-01								
Benzene	2.10E-03	7.21E-04	1.73E-02	6.31E+00								
Beryllium	1.20E-05	4.12E-06	9.88E-05	3.61E-02								
Cadmium	1.10E-03	3.78E-04	9.06E-03	3.31E+00								
Chlorobenzene												
Chromium	1.40E-03	4.80E-04	1.15E-02	4.21E+00								
Cobalt	8.40E-05	2.88E-05	6.92E-04	2.53E-01								
ethyl benzene												
Ethylene Dichloride												
Formaldehdye	7.50E-02	2.57E-02	6.18E-01	2.25E+02								
Hexane	1.80E+00	6.18E-01	1.48E+01	5.41E+03								
Hydrogen Chloride												
Manganerse	3.80E-04	1.30E-04	3.13E-03	1.14E+00								
Mercury	2.60E-04	8.92E-05	2.14E-03	7.82E-01								
Methanol					4.28E-10	1.28E-05	3.08E-04	1.12E-01	3.12E-06	3.12E-06	7.49E-05	2.73E-02
Methylene Chloride												
naphthalene												
Nickel	2.10E-03	7.21E-04	1.73E-02	6.31E+00								
Selenium	2.40E-05	8.24E-06	1.98E-04	7.22E-02								
Tetrachloroethylene												
Toluene	3.40E-03	1.17E-03	2.80E-02	1.02E+01								
Trichloroethylene												
Xylenes												
Total (lbs/yr)				**5.67E+03**				**1.12E-01**				**2.73E-02**
Total (tons/yr)				**2.84E+00**				**5.62E-05**				**1.37E-05**

	EU 027 - Diesel Generator				EU 030 Misc NG Units				EU 025 Biogas Flare			
	Fuel Usage	232.82	MMBtu/yr		Fuel Usage	85.88	MMCF/yr		Fuel Usage	78.84	MMCF/yr	
		0.47	MMBtu/hr			0.01	MMCF/hr			0.009	MMCF/hr	
HAP	EF (lb/MMBTU)	lb/hr	lb/day	lb/yr	EF (lb/MMCF)	lb/hr	lb/day	lb/yr	EF (lb/MMCF)	lb/hr	lb/day	lb/yr
1,3 Butadiene	3.91E-05	1.82E-05	4.37E-04	9.10E-03								
Acetaldehyde	7.67E-04	3.57E-04	8.57E-03	1.79E-01								
Arsenic					2.00E-04	1.96E-06	4.71E-05	1.72E-02				
Benzene	9.33E-04	4.34E-04	1.04E-02	2.17E-01	2.10E-03	2.06E-05	4.94E-04	1.80E-01	2.77E-02	2.49E-04	5.98E-03	2.18E+00
Beryllium					1.20E-05	1.18E-07	2.82E-06	1.03E-03				
Cadmium					1.10E-03	1.08E-05	2.59E-04	9.45E-02				
Chlorobenzene									0.0002	1.80E-06	4.32E-05	1.58E-02
Chromium					1.40E-03	1.37E-05	3.29E-04	1.20E-01				
Cobalt					8.40E-05	8.24E-07	1.98E-05	7.21E-03				
ethyl benzene									1.00E-03	9.00E-06	2.16E-04	7.88E-02
Ethylene Dichloride									0.0014	1.26E-05	3.02E-04	1.10E-01
Formaldehdye	1.18E-03	5.49E-04	1.32E-02	2.75E-01	7.50E-02	7.35E-04	1.76E-02	6.44E+00	2.04E-01	1.84E-03	4.41E-02	1.61E+01
Hexane					1.80E+00	1.76E-02	4.24E-01	1.55E+02	1.01E-02	9.09E-05	2.18E-03	7.96E-01
Hydrogen Chloride									6.46E-01	5.81E-03	1.39E-01	5.09E+01
Manganerse					3.80E-04	3.73E-06	8.94E-05	3.26E-02				
Mercury					2.60E-04	2.55E-06	6.12E-05	2.23E-02				
Methanol												
Methylene Chloride									0.0001	9.00E-07	2.16E-05	7.88E-03
naphthalene	8.48E-05	3.95E-05	9.48E-04	1.97E-02								
Nickel					2.10E-03	2.06E-05	4.94E-04	1.80E-01				
Selenium					2.40E-05	2.35E-07	5.65E-06	2.06E-03				
Tetrachloroethylene									0.0005	4.50E-06	1.08E-04	3.94E-02
Toluene	4.09E-04	1.90E-04	4.57E-03	9.52E-02	3.40E-03	3.33E-05	8.00E-04	2.92E-01	1.01E-02	9.09E-05	2.18E-03	7.96E-01
Trichloroethylene									0.0003	2.70E-06	6.48E-05	2.37E-02
Xylenes	2.85E-04	1.33E-04	3.18E-03	6.64E-02					4.50E-03	4.05E-05	9.72E-04	3.55E-01
Total (lbs/yr)				**8.61E-01**				**1.62E+02**				**7.14E+01**
Total (tons/yr)				**4.30E-04**				**8.10E-02**				**3.57E-02**

EU 028 - Natural Gas-Fired Boiler
Potential Emissions

Potential Emissions

Emission Factors:

PM[1]	7.60	lb/MMCF
PM10[3]	0.005	lb/MMBtu
PM2.5[2]	0.0016	lb/MMBtu
SO2[1]	0.60	lb/MMCF
CO[3]	0.037	lb/MMBtu
NOX[3]	0.018	lb/MMBtu
VOC[3]	0.004	lb/MMBtu
CO2e	Note 4	
Lead	0.0005	lb/MMCF

Heat Input Capacity:

350.05 MMBtu/hr

Operating Schedule:

24 hours/day
365 days/year

Potential Emissions[5]:

PM	2.61	lb/hr	11.42	tons/yr
PM10	1.75	lb/hr	7.67	tons/yr
PM2.5	0.57	lb/hr	2.51	tons/yr
SO2	0.21	lb/hr	0.90	tons/yr
CO	12.95	lb/hr	56.73	tons/yr
NOX	6.38	lb/hr	27.93	tons/yr
VOC	1.40	lb/hr	6.13	tons/yr
CO2-e			179,392	tons/yr
Lead	1.72E-04	lb/hr	7.52E-04	tons/yr

Notes

(1) PM and SO2 emission factors from USEPA's AP-42, Chapter 1.4. To convert to MMBtu, 1,020 MMBtu/MMCF was assumed.

(2) PM2.5 emission factor obtained from the National Council for Air and Stream Improvement, Inc.'s (NCASI) May 31, 2013 comments to USEPA's March 4, 2013 draft guidance for PM2.5 permit modeling. A safety factor of 2 has been applied.

(3) PM10, CO, NOx, and VOC emission factors supplied by boiler manufacturer.

(4) CO2e emissions calculated using 40 CFR 98 Subpart C Tier 1 methodology. See GHG Calculations for details.

(5) The boiler will also combust a portion of the biogas collected from the anaerobic digester. Natural gas usage is expected to far outweigh biogas usage in the boiler. The digester will also have a biogas flare, identified as EU 025; emission estimates for the flare assumed 8,760 hours of operation; therefore emissions from biogas combustion are accounted for under EU 025.

EU 029 - Paper Machine
Potential Emissions

Potential Emissions

Emission Factors[1]:

	Machine Production		Hydrapulping Production	
PM				
PM10				
PM2.5				
SO2				
CO				
NOX				
VOC	0.2300	lb/ADTFP	0.012	lb/ODTP
CO2e				

Linerboard Production:

1,600 tons/day ADTFP
1,440 tons/day ODTP

Operating Schedule:

24 hours/day
365 days/year

Potential Emissions:

PM	-	lb/hr	-	tons/yr
PM10	-	lb/hr	-	tons/yr
PM2.5	-	lb/hr	-	tons/yr
SO2	-	lb/hr	-	tons/yr
CO	-	lb/hr	-	tons/yr
NOX	-	lb/hr	-	tons/yr
VOC	16.05	lb/hr	70.31	tons/yr
CO2-e			-	tons/yr

Notes

(1)The paper machine will operate in a manner similar to Pratt's recycle mill in Shreveport, LA. Therefore, emission factors from the Shreveport mill's permit application were used to determine VOC emissions from the paper machine. ADTFP = air dried tons of finished product; ODTP = oven dried tons of pulp. Assumes ODTP = 90% ADTFP.

EU 022 - Starch Silo
Potential Emissions

Potential Emissions

Emission Factors[1]:

PM	0.25	lb/ton
PM10	0.25	lb/ton
PM2.5	0.25	lb/ton
SO2		
CO		
NOX		
VOC		
CO2e		

Silo Throughput

2.75 tons/hour of starch

Operating Schedule:

24 hours/day
365 days/year

Potential Emissions:

PM	0.674	lb/hr	2.95	tons/yr
PM10	0.674	lb/hr	2.95	tons/yr
PM2.5	0.674	lb/hr	2.95	tons/yr
SO2	-	lb/hr	-	tons/yr
CO	-	lb/hr	-	tons/yr
NOX	-	lb/hr	-	tons/yr
VOC	-	lb/hr	-	tons/yr
CO2-e			-	tons/yr

Notes

(1) Emission factors calculated using EPA's AP-42, Table 9.9.7-1, for Starch Storage Silo. The emission factor provided in AP-42 was for a silo controlled with a baghouse; a control efficiency of 99% was assumed to calculate uncontrolled emissions. Additionally, to convert the emission factor from lbs/ton of corn to lbs/ton of starch, it was assumed that for every bushel of corn (56 lbs), there was 32 lbs of starch (AP-42 Chapter 9.9.7). Emissions assume PM = PM10 = PM2.5.

EU 023 - WWTP Effluent Cooling Tower
Potential Emissions

Potential Emissions

Emission Factors:

PM[3]	0.019	lb/1000 gal
PM10[1]	0.019	lb/1000 gal
PM2.5[3]	0.019	lb/1000 gal
SO2		
CO		
NOX		
VOC[2]	1.38E-05	lb/hr
CO2e		

Throughput

500 gallons/min

Operating Schedule:

24 hours/day
365 days/year

Potential Emissions:

PM	0.57	lb/hr	2.50	tons/yr
PM10	0.57	lb/hr	2.50	tons/yr
PM2.5	0.57	lb/hr	2.50	tons/yr
SO2	-	lb/hr	-	tons/yr
CO	-	lb/hr	-	tons/yr
NOX	-	lb/hr	-	tons/yr
VOC	1.38E-05	lb/hr	6.04E-05	tons/yr
CO2-e			-	tons/yr

Notes

(1) PM10 emission factor from USEPA's AP-42, Table 13.4-1 (for induced draft cooling tower)

(2) VOC emissions based on the Pratt - Shreveport mill wastewater treatment plant influent and effluent data. Emissions were calculated using Water9, Version 2 and are comprised of methanol and pinene(alpha-). A safety factor of 2 has been applied.

(3) It was assumed PM and PM2.5 are equal to PM10

EU 024 - WWTP Equilization Tank
Potential Emissions

Potential Emissions

Emission Factors:

PM		
PM10		
PM2.5		
SO2		
CO		
NOX		
VOC[1]	3.14E-06	lb/hr
CO2e		

Operating Schedule:

24	hours/day
365	days/year

Potential Emissions:

PM	-	lb/hr	-	tons/yr
PM10	-	lb/hr	-	tons/yr
PM2.5	-	lb/hr	-	tons/yr
SO2	-	lb/hr	-	tons/yr
CO	-	lb/hr	-	tons/yr
NOX	-	lb/hr	-	tons/yr
VOC	3.14E-06	lb/hr	1.38E-05	tons/yr
CO2-e			-	tons/yr

Notes

(1) VOC emissions based on the Pratt - Shreveport mill wastewater treatment equilization tank data. A safety factor of 2 has been applied.

EU 025 - Biogas Flare
Potential Emissions

Potential Emissions

Emission Factors:

PM[1]	17.00	lb/MMCF methane
PM10[2]	12.00	lb/MMCF biogas
PM2.5[3]	12.00	lb/MMCF biogas
SO2[2]	2.00	lb/MMCF biogas
CO[2]	1.80	lb/MMCF biogas
NOX[1]	40.00	lb/MMCF methane
VOC[2]	6.30	lb/MMCF biogas
CO2e	Note 4	

Throughput

216,000	scf biogas/day
153.90	MMBtu/day

Biogas Properties

	% Composition	Throughput (MMCF/hr)
CH4	75%	6.75E-03
CO2	25%	2.25E-03

Operating Schedule:

24	hours/day
365	days/year

Potential Emissions:

PM	0.11	lb/hr	0.50	tons/yr
PM10	0.11	lb/hr	0.47	tons/yr
PM2.5	0.11	lb/hr	0.47	tons/yr
SO2	0.02	lb/hr	0.08	tons/yr
CO	0.02	lb/hr	0.07	tons/yr
NOX	0.27	lb/hr	1.18	tons/yr
VOC	0.06	lb/hr	0.25	tons/yr
CO2-e			3,825	tons/yr

Notes

(1) PM, NOx emission factors from USEPA's AP-42, Table 2.4-5

(2) Emission factor based on San Diego APCD's Air Toxics Emissions Calculation Procedures for Flares, Digester Gas Fired, Enclosed (last updated 8/23/99 by A. dela Cruz) and assumes a methane concentration of 75%.

(3) It was assumed PM2.5 was equal to PM10.

(4) CO2e emissions calculated using 40 CFR 98 Subpart C Tier 1 methodology. See GHG Calculations for details.

EU 026 - Fire Pump Diesel Tank
Potential Emissions

See TANKS 4.0.9d Emission Report for emissions determination.

Tank Capacity

1,000 gallons

Diesel Usage[1]:

1,687 gallons/year

Working Losses from TANKS 4.0

0.03 lb/yr

Breathing Losses from TANKS 4.0

0.26 lb/yr

Potential Emissions:

PM	-	lb/hr	-	tons/yr
PM10	-	lb/hr	-	tons/yr
PM2.5	-	lb/hr	-	tons/yr
SO2	-	lb/hr	-	tons/yr
CO	-	lb/hr	-	tons/yr
NOX	-	lb/hr	-	tons/yr
VOC	<0.1	lb/hr	1.45E-04	tons/yr
CO2-e				tons/yr

Notes

(1) Annual diesel usage based on fire pump (EU 027) usage:

Hourly fire pump throughput of 0.47 MMBtu/hr x 500 hr/yr x HHV of 0.138 MMBtu/Gallon = 1687 gallons/yr

EU 027 - Emergency Fire Pump
Potential Emissions

Potential Emissions

Emission Factors[1]:

PM[2]	0.31	lb/MMBtu
PM10	0.31	lb/MMBtu
PM2.5[2]	0.31	lb/MMBtu
SO2	0.29	lb/MMBtu
CO	0.95	lb/MMBtu
NOX	4.41	lb/MMBtu
VOC	0.36	lb/MMBtu
CO2e	Note 3	

Heat Input Capacity:

0.47 MMBtu/hr

Operating Schedule[4]:

500 hr/yr

Potential Emissions:

PM	0.14	lb/hr	0.04	tons/yr
PM10	0.14	lb/hr	0.04	tons/yr
PM2.5	0.14	lb/hr	0.04	tons/yr
SO2	0.14	lb/hr	0.03	tons/yr
CO	0.44	lb/hr	0.11	tons/yr
NOX	2.05	lb/hr	0.51	tons/yr
VOC	0.17	lb/hr	0.04	tons/yr
CO2-e			19.04	tons/yr

Notes

(1) Emission factors from USEPA's AP-42, Table 3.3-1

(2) It was assumed PM and PM2.5 are equal to PM10

(3) CO2e emissions calculated using 40 CFR 98 Subpart C Tier 1 methodology. See GHG Calculations for details.

(4) Per the memorandum from John S. Seitz, Director of the Office of Air Quality Planning and Standards, U.S. EPA, titled "Calculating Potential to Emit for Emergency Generators", dated September 6, 1995, 500 hours per year was determined to be an appropriate default assumption for estimating the number of hours an emergency generator could be expected to operate under worst-case conditions.

EU 030 - Natural Gas-Fired AMUs
Potential Emissions

Potential Emissions

Emission Factors:

PM[1]	7.60	lb/MMCF
PM10	7.60	lb/MMCF
PM2.5[2]	0.0016	lb/MMBtu
SO2	0.60	lb/MMCF
CO	84	lb/MMCF
NOX	100	lb/MMCF
VOC	5.5	lb/MMCF
CO2e	Note 4	
Lead	0.0005	lb/MMCF

Heat Input Capacity[3]:

10.00	MMBtu/hr
0.010	MMCF/hr

Operating Schedule:

24	hours/day
365	days/year

Potential Emissions:

PM	0.07	lb/hr	0.33	tons/yr
PM10	0.07	lb/hr	0.33	tons/yr
PM2.5	0.02	lb/hr	0.07	tons/yr
SO2	0.01	lb/hr	0.03	tons/yr
CO	0.82	lb/hr	3.61	tons/yr
NOX	0.98	lb/hr	4.29	tons/yr
VOC	0.05	lb/hr	0.24	tons/yr
CO2-e			5,125	tons/yr
Lead	4.90E-06	lb/hr	2.15E-05	tons/yr

Notes

(1) Emission factors from USEPA's AP-42, Chapter 1.4.

(2) PM2.5 emission factor obtained from the National Council for Air and Stream Improvement, Inc.'s (NCASI) May 31, 2013 comments to USEPA's March 4, 2013 draft guidance for PM2.5 permit modeling. A safety factor of 2 has been applied.

(3) There are three air makeup units with a combined heat input capacity of 10 MMBtu/hr. To convert to MMBtu, 1,020 MMBtu/MMCF was assumed.

(4) CO2e emissions calculated using 40 CFR 98 Subpart C Tier 1 methodology. See GHG Calculations for details.

Greenhouse Gas Emissions

Global Warming Potential		
CO_2	CH_4	N_2O
1	21	310

1 metric ton = 1.102311 tons

Unit ID	Description	Fuel Type	Potential Annual Consumption		Default HHV		GHG Emission Factors (EF)			GHG Emissions - Potential metric tons per year			TOTAL - CO_2e (tons per year)
							CO_2 EF	CH_4 EF	N_2O EF				
			Value	Units	Value	Units	(kg/MMBtu)	(kg/MMBtu)	(kg/MMBtu)	CO_2	CH_4	N_2O	
EU 028	**Boiler**	NG	3,066,438	MMBtu/yr	0.001028	mmBtu/scf	53.02	1.00E-03	1.00E-04	162,582.54	3.07	0.31	179,392.29
EU 025	**Biogas Flare**	Biogas	78,840,000	SCF/yr	0.000841	MMBtu/SCF	52.07	3.20E-03	6.40E-04	3,452.47	0.21	0.04	3,825.11
EU 027	**Emergency generator**	Diesel	232.82	MMBtu/yr	0.138000	MMBtu/gallon	73.96	3.00E-03	6.00E-04	17.22	0.00	0.00	19.04
EU 030	**Misc. natural gas-fired units**	NG	87,600	MMBtu/yr	0.001028	mmBtu/scf	53.02	1.00E-03	1.00E-04	4,644.55	0.09	0.01	5,124.76
													188,361

Notes

(1) Calculations based on 40 CFR Part 98, Subpart C Tier 1 Calculation Methodology. Emission factors and default HHV values from 40 CFR Part 98 Tables C-1 and C-2

(2) Biogas is combusted in either flare or boiler; it was assumed GHG emissions would be the same regardless of which unit it was combusted in.

(3) Assuming No. 2 fuel oil and limited to 200 hrs/yr

Appendix A: Emissions Calculations
VOC From Printing Press Operations

Company Name: Jet Corr, Inc.
Address City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number : 127-33924-00094
Reviewer: Josiah Balogun
Date: 12-Nov-13

94.5-inch Emba Press, EU 005

THROUGHPUT								
Press I.D. **EU 005**	MAXIMUM LINE SPEED FEET PER MINUTE	CONVERT FEET TO INCHES	MAXIMUM PRINT WIDTH INCHES	60 MIN HOUR	8760 HR YEAR	1/1000000	MMin^2/YR	MMin^2/HR
	957	12	94.5	60	8760	1000000	570401.0928	65.1

INK						
Press Id	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
EU 005						
Worst Case VOC	1.5	2%	100.00%	570401	2000	**8.56**
INK HAPs						
Worst Case HAP	1.5	1%	100.00%	570401	2000	**4.28**

METHODOLOGY For Presses And Gluer Machines
Throughput = Maxium line speed feet per minute * Convert feet to inches * Maximum print width inches * 60 minutes per hour * 8760 hours per year = MMin^2 per Year
VOC = Maximum Coverage pounds per MMin^2 * Weight percentage volatiles (water minus organics) * Flash off * Throughput * Tons per 2000 pounds = Tons per Year

NOTE: HEAT SET OFFSET PRINTING HAS AN ASSUMED FLASH OFF OF 80%; NON HEAT SET FLASH OFF = 5%. OTHER TYPES OF PRINTERS HAVE A FLASH OFF OF 100%.

EU 003 & 004 48-inch Color Flexo Folder & Gluer Machines

TOTAL THROUGHPUT	**Total**						
Press I.D. **EU 003 & EU 004**	MAXIMUM LINE SPEED FEET PER MINUTE	CONVERT FEET TO INCHES	MAXIMUM PRINT WIDTH INCHES	60 MIN HOUR	8760 HR YEAR	1/1000000	MMin^2/YR
	2500	12	48	60	8760	1000000	756864

INK						
Press Id	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
EU 003 & EU 004						
Worst Case VOC	1.5	2%	100.00%	756864	2000	11.35
INK HAPs						
Worst Case HAP	1.5	1%	100.00%	756864	2000	5.68
Adhesives Worst Case VOCs						
XR-6463 PN	0.124	10.03%	100.00%	756864	2000	4.69
XR-6463 RE	0.191	13.22%	100.00%	756864	2000	9.58
PA-3501 RB	0.129	0.55%	100.00%	756864	2000	0.269
Cleaning Solvent	0.022	11.00%	100.00%	756864	2000	0.927
					Total VOC	**26.8**
Adhesives HAPs Worst Case						
XR-6463 PN	0.124	10.03%	100.00%	756864	2000	4.69
XR-6463 RE	0.191	10.03%	100.00%	756864	2000	7.27
PA-3501 RB	0.129	0.025%	100.00%	756864	2000	0.012
Cleaning Solvent	0.022	0.00%	100.00%	756864	2000	0.000
					Total HAPs	**17.64**

EU 012 2-Color Flexographic Folder & Gluer Machine

TOTAL THROUGHPUT	Total						
Press I.D. **EU 012**	MAXIMUM LINE SPEED FEET PER MINUTE	CONVERT FEET TO INCHES	MAXIMUM PRINT WIDTH INCHES	60 MIN HOUR	8760 HR YEAR	1/1000000	MMin^2/YR
	1708.33	12	89	60	8760	1000000	958957

INK						
Press Id	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
EU 012						
Worst Case VOC	0.93	1.8%	100.00%	958957	2000	8.03
INK HAPs						
Worst Case HAP	0.93	1%	100.00%	958957	2000	**4.46**
Adhesives						
Worst Case VOC	0.523	0.52%	100.00%	958957	2000	1.31
					Total VOC	**9.33**

EU 018 Flexographic Printer-Folder Gluer Machine

TOTAL THROUGHPUT	Total							
Press I.D. **EU 018**	MAXIMUM LINE SPEED FEET PER MINUTE	CONVERT FEET TO INCHES	MAXIMUM PRINT WIDTH INCHES	60 MIN HOUR	8760 HR YEAR	1/1000000	MMin^2/YR	MMin^2/hr
		12		60	8760	1000000	693792.0	79.2

INK						
Press Id	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
EU 018						
Worst Case VOC	0.93	1.8%	100.00%	693792.0	2000	5.81
INK HAPs						
Worst Case HAP	0.0015	100%	100.00%	693792	2000	**0.520**
Adhesives						
Worst Case VOC	0.523	0.63%	100.00%	693792	2000	1.14
					Total VOC	**6.95**

THROUGHPUT								
Press I.D. **EU 019**	MAXIMUM LINE SPEED FEET PER MINUTE	CONVERT FEET TO INCHES	MAXIMUM PRINT WIDTH INCHES	60 MIN HOUR	8760 HR YEAR	1/1000000	MMin^2/YR	MMin^2/HR
	925	12	94.5	60	8760	1000000	551328.1200	62.9

INK						
Press Id	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
EU 005						
Worst Case VOC	1.5	2%	100.00%	551328	2000	**8.27**
INK HAPs						
Worst Case HAP	1.5	1%	100.00%	551328	2000	**4.13**

2 CORRUGATING MACHINES EU 006	CAPACITY SQUARE FEET PER HOUR	CONVERT FEET TO SQUARE INCHES PER HOUR	CAPACITY SQUARE INCHES PER HOUR	HOUR PER HOUR	8760 HR YEAR	1/1000000	MMin^2/YR
EU 006	328768	144	47342592	1	8760	1000000	414721

Capacity = 164,384 sq ft/hr each

MATERIALS VOCS						
Materials	Maxium Coverage lbs/MMin^2	Weight % Volatiles*	Flash Off %	Through Put MMin^2/Year	Tons 2000 lbs	Tons Year
2 CORRUGATING MACHINES						
B121 Biocide	7.72E-03	0.50%	100.00%	414721	2000	0.00800
210 Resin	2.08E-02	1.00%	100.00%	414721	2000	0.043
#677 Colloids	7.72E-03	0.185%	100.00%	414721	2000	0.0030
Cleanup Solvent	4.82E-02	100.00%	100.00%	414721	2000	10.00
					Total VOC	**10.1**
MATERIAL HAPS						
B121 Biocide	7.72E-03	1.00%	100.00%	414721	2000	0.01600
210 Resin	2.08E-02	0.00%	100.00%	414721	2000	0.000
#677 Colloids	7.72E-03	0.000%	100.00%	414721	2000	0.0000
Cleanup Solvent	4.82E-02	0.00%	100.00%	414721	2000	0.00
					Total HAPs	**0.016**

SUMMARY OF PROCESS VOCS & HAPS

Emission Unit	**VOC** (tons/year)	**Worse Case HAP** (tons/year)
EU 005	8.56	4.28
EU 003	13.4	8.82
EU 004	13.4	8.82
EU 012	9.33	4.46
EU 018	6.95	0.520
EU 019	8.27	4.13
EU 006	10.1	0.016
Subtotal	**70.0**	**31.1**

Baler System EU 009

The cyclone was determined to be integral part of the process by SPR 127-16841-00094, issued on March 10, 2003.
The potential to emit after control takes into account the baghouse control which brings the overall control to 99.9%.

6,400 lbs of scrap per hour processed					**After baghouse**	lbs/hr	6.40
PTE after cyclone = 99.9%	PTE after cyclone = 6,400 lbs/hr * (1- 0.999) =		6.4	lbs/hr	**Control**	tons/yr	28.0
PM is assumed to equal PM10		PM = PM10	**28.0**	tons/yr			

Appendix A: Emissions Calculations
VOC From Flexographic Printer-Folder Gluer Machine (EU 021)

Company Name: Jet Corr, Inc.
Address City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Operation Permit No.: 127-33924-00094
Permit Reviewer: Josiah Balogun
Application Date: 12-Nov-13

Press I.D. **EU 021**	SHEET WIDTH (inches)	SHEET LENGTH (inches)	MACHINE SPEED (sheets/min)	THROUGHPUT (MMin^2/yr)
	35	94	325	561997.8

	MAX COVERAGE (lb/MMin^2)	WEIGHT % VOLATILES*	FLASH OFF %	EMISSIONS (ton/yr)
Worst Case VOC	0.93	1.8	100	**4.70**
Worst Case HAP	0.0015	100	100	**0.42**
Adhesives VOC	0.523	0.63	100	**0.93**

* Coverage and volatile assumptions same as EU 018 (calculation in Appendix A of FESOP Renewal 127-19359-00094)

TOTAL VOC (tpy)	**5.63**
TOTAL HAP (tpy)	**0.42**

Methodology

Throughput (Mmin^2/yr) = Sheet Width (inches) x Sheet Length (inches) x Machine Speed (sheets/min) x 60 Min/hr x 8760 hr/yr
Worst Case VOC (tpy) = Throughput (Mmin^2/yr) x Max Coverage (lb/Mmin^2) x Weight % Volatiles x Flash off % x 1 ton/2000 lb
Worst Case HAP (tpy) = Throughput (Mmin^2/yr) x Max Coverage (lb/Mmin^2) x Weight % Volatiles x Flash off % x 1 ton/2000 lb
Adhesives VOC (tpy) = Throughput (Mmin^2/yr) x Max Coverage (lb/Mmin^2) x Weight % Volatiles x Flash off % x 1 ton/2000 lb
TOTAL VOC (tpy) = Worst Case VOC (tpy) + Adhesives VOC (tpy)
TOTAL HAP (tpy) = Worst Case HAP (tpy)

Appendix A: Emissions Calculations
Natural Gas Combustion Only - EU 001 & 013
MM BTU/HR <100

Company Name: Jet Corr, Inc.
Address City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Reviewer: Josiah Balogun
Date: 12-Nov-13

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
41.8	1020	359.3

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	50 **see below	5.5	84
Potential Emission in tons/yr	0.3	1.4	1.4	0.1	9.0	0.99	15.1

*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

HAPS Calculations

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
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	3.773E-04	2.156E-04	1.347E-02	3.234E-01	6.109E-04	**3.381E-01**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
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	8.983E-05	1.976E-04	2.515E-04	6.827E-05	3.773E-04	**9.846E-04**
					Total HAPs	**3.391E-01**
					Worst HAP	**3.234E-01**

Methodology is the same as above.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Greenhouse Gas Calculations

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	117	2.205E-03	2.205E-04
Potential Emission in tons/yr	21,421	0.404	0.0404
Summed Potential Emissions in tons/yr	21,421		
CO2e Total in tons/yr	21,442		

Methodology
Calculations based on 40 CFR Part 98, Subpart C Tier 1 Calculation Methodology. Emission factors from 40 CFR Part 98 Tables C-1 and C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMBtu/hr) x 8,760 (hr/yr) x Emission Factor (lb/MMBtu)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr) - EU 001 & 013
#1 and #2 Fuel Oil

Company Name: **Jet Corr, Inc.**
Address, City IN Zip: **3155 State Road 49, Valparaiso, Indiana 46383**
Permit Number: **127-33924-00094**
Reviewer: **Josiah Balogun**
Date: **12-Nov-13**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.5
41.84	2617.988571	

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	78.5 *(157S)*	20.0	0.20	5.0
Potential Emission in tons/yr	2.6	3.0	2.0	102.8	26.2	0.3	6.5

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-02-005-01/02/03) Supplement E 9/98
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
#1 and #2 Fuel Oil
HAPs Emissions

Company Name: Jet Corr, Inc.
Address, City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Reviewer: Josiah Balogun
Date: 12-Nov-13

	HAPs - Metals				
	Arsenic	Beryllium	Cadmium	Chromium	Lead
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06
Potential Emission in tons/yr	7.33E-04	5.50E-04	5.50E-04	5.50E-04	1.65E-03

	HAPs - Metals (continued)			
	Mercury	Manganese	Nickel	Selenium
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05
Potential Emission in tons/yr	5.50E-04	1.10E-03	5.50E-04	2.75E-03

Methodology

No data was available in AP-42 for organic HAPs.

Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

See Page 30 for Greenhouse Gas calculations.

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
#1 and #2 Fuel Oil
Greenhouse Gas Emissions

Company Name: **Jet Corr, Inc.**
Address, City IN Zip: **3155 State Road 49, Valparaiso, Indiana 46383**
Permit Number: **127-33924-00094**
Reviewer: **Josiah Balogun**
Date: **12-Nov-13**

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/kgal	163	0.00661	0.001323
Potential Emission in tons/yr	29,881	1.212	0.242
Summed Potential Emissions in tons/yr	29,883		
CO2e Total in tons/yr	29,982		

Methodology
Calculations based on 40 CFR Part 98, Subpart C Tier 1 Calculation Methodology. Emission factors from 40 CFR Part 98 Tables C-
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMBtu/hr) x 8,760 (hr/yr) x Emission Factor (lb/MMBtu)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr) - EU 001 & 013
#1 and #2 Fuel Oil

Company Name: **Jet Corr, Inc.**
Address, City IN Zip: **3155 State Road 49, Valparaiso, Indiana 46383**
Permit Number: **127-33924-00094**
Reviewer: **Josiah Balogun**
Date: **12-Nov-13**

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
41.84	350	0.5

	Pollutant						
	PM*	PM10	direct PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	2.0	2.3	1.6	78.5 *(157S)*	20.0	0.20	5.0
Potential Emission in tons/yr	0.4	0.4	0.3	13.7	3.5	0.04	0.9

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 1.3-1, 1.3-2, and 1.3-3 (SCC 1-02-005-01/02/03) Supplement E 9/98
*PM emission factor is filterable PM only. Condensable PM emission factor is 1.3 lb/kgal.
Emission (tons/yr) = Throughput (kgals/ yr) x Emission Factor (lb/kgal)/2,000 lb/ton

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
#1 and #2 Fuel Oil
HAPs Emissions

Company Name: Jet Corr, Inc.
Address, City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Reviewer: Josiah Balogun
Date: 12-Nov-13

	HAPs - Metals				
	Arsenic	Beryllium	Cadmium	Chromium	Lead
Emission Factor in lb/mmBtu	4.0E-06	3.0E-06	3.0E-06	3.0E-06	9.0E-06
Potential Emission in tons/yr	7.33E-04	5.50E-04	5.50E-04	5.50E-04	1.65E-03

	HAPs - Metals (continued)			
	Mercury	Manganese	Nickel	Selenium
Emission Factor in lb/mmBtu	3.0E-06	6.0E-06	3.0E-06	1.5E-05
Potential Emission in tons/yr	5.50E-04	1.10E-03	5.50E-04	2.75E-03

Methodology

No data was available in AP-42 for organic HAPs.

Potential Emissions (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

See Page 33 for Greenhouse Gas calculations.

Appendix A: Emissions Calculations
Industrial Boilers (> 100 mmBtu/hr)
#1 and #2 Fuel Oil
Greenhouse Gas Emissions

Company Name: **Jet Corr, Inc.**
Address, City IN Zip: **3155 State Road 49, Valparaiso, Indiana 46383**
Permit Number: **127-33924-00094**
Reviewer: **Josiah Balogun**
Date: **12-Nov-13**

Default Higer Heating Value of No. 2 fuel Oil	**0.138**	MMBtu/gal
Annual Limited Heat Input	48300	MMBtu/year

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/kgal	163	0.00661	0.001323
Potential Emission in tons/yr	3,938	0.15972	0.0319
Summed Potential Emissions in tons/yr	3,938		
CO2e Total in tons/yr	3,951		

Methodology
Calculations based on 40 CFR Part 98, Subpart C Tier 1 Calculation Methodology. Emission factors and default HHV from 40
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (350 kgal/yr) x 1,000 (gal/kgal) x HHV (MMBtu/gal) x Emission Factor (lb/MMBtu)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x N2O GWP (310).

Appendix A: Emissions Calculations
Natural Gas Combustion Only - EU 011
MM BTU/HR <100

Company Name: Jet Corr, Inc.
Address City IN Zip: 3155 State Road 49, Valparaiso, Indiana 46383
Permit Number: 127-33924-00094
Reviewer: Josiah Balogun
Date: 12-Nov-13

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
39.2	1020	336.9

	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	0.3	1.3	1.3	0.1	16.8	0.9	14.2

*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

HAPS Calculations

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
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	3.538E-04	2.021E-04	1.263E-02	3.032E-01	5.728E-04	**3.170E-01**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
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	8.423E-05	1.853E-04	2.358E-04	6.401E-05	3.538E-04	**9.232E-04**
					Total HAPs	**3.179E-01**
					Worst HAP	**3.032E-01**

Methodology is the same as above.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Greenhouse Gas Calculations

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	117	2.205E-03	2.205E-04
Potential Emission in tons/yr	20,085	0.379	0.0379
Summed Potential Emissions in tons/yr	20,085		
CO2e Total in tons/yr	20,104		

Methodology
Calculations based on 40 CFR Part 98, Subpart C Tier 1 Calculation Methodology. Emission factors from 40 CFR Part 98 Tables C-1 and C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMBtu/hr) x 8,760 (hr/yr) x Emission Factor (lb/MMBtu)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential Emission ton/yr x

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)

Source Background and Description

Source Name:	**Jet Corr, Inc**
Source Location:	**3155 State Road 49, Valparaiso, IN 46383**
County:	**Porter**
SIC Code:	**2653, 2631**
Operation Permit No.:	**F 127-19359-00094**
Operation Permit Issuance Date:	**February 10, 2006**
Title V Operating Permit No.:	**T127-33924-00094**
Permit Reviewer:	**Josiah Balogun**

Proposed Expansion

Jet Corr, Inc is proposing to install a new recycle mill in their existing plant in Porter County. Jet Corr, Inc is proposing to expand the Jet Corr facility by adding a 100% recycled paperboard mill. The new recycle mill will include a paper machine with wet end pulping and chemical addition operations and steam drying, along with other air emission sources such as starch silos, and other minor process equipment. The new mill will be supported by a boiler capable of combusting natural gas and biogas collected from the wastewater pretreatment plant.

PSD applicability based on GHG emissions requires that potential emissions be greater than 100,000 tons per year of CO_2e for new sources and mass-based GHG emissions greater than the applicable PSD major source threshold of 100 or 250 tons per year. The potential CO_2e emissions from the proposed new mill exceed 100,000 tons per year and 250 tons per year mass-based. Therefore, the new recycle mill will be considered a new major stationary source under PSD for GHG.

Jet Corr, Inc is located at 3155 State Road 49, Valparaiso, IN 46383, in Porter County. Jet Corr, Inc submitted a PSD and Title V operating permit application to IDEM, OAQ on October 2, 2013,

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed New Recycle Mill because the new construction to an existing plant has the potential to emit CO_2e emissions greater than 100,000 tons per year, which exceeds the PSD threshold and significant levels for this pollutant.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

Proposed New Emission Units

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed emission units:

(a) One (1) natural gas fired-boiler, with biogas as backup, identified as EU 028, permitted in 2014, with heat input capacity of 350 MMBtu/hr, equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks S 028A and B. The boiler will be equipped with a continuous emissions monitoring system (CEMS) for NOx and diluent (O_2 or CO_2). [Under 40 CFR Part 60, Subpart Db, the boiler is considered a steam generating unit]

(b) One (1) biogas flare, identified as EU 025, permitted in 2014, with a throughput of 216,000scf of biogas per day (153.9 MMBtu/day) and exhausting to stack S 025.

(c) One (1) Emergency diesel fire pump engine, rated at 183 horsepower (HP) and identified as EU 027, permitted in 2014, and exhausting to stack S 027. [Under 40 CFR 60, Subpart IIII, the fire pump engine is considered new affected source]

(d) Three (3) natural gas-fired air make up units, identified as EU 030, permitted in 2014, with a combined capacity of 10 MMBtu per hour, exhausting through Stack S030.

Summary of the Best Available Control Technology (BACT) Process

BACT is an emission limitation based on the maximum degree of pollution reduction of emissions, which is achievable on a case-by-case basis. BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. There will still be air pollution from this project; however, Jet Corr, Inc will be required to demonstrate that the emissions will be reduced to the maximum extent.

Federal EPA generally requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. IDEM evaluates BACT based on a "top down" approach.

The five (5) basic steps of a top-down BACT analysis used by the Office of Air Quality (OAQ) to make BACT determinations are listed below:

Step 1: Identify Potential Control Technologies
The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories.

Step 2: Eliminate Technically Infeasible Options
The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls if proposed by the source. Only available and proven control technologies are evaluated. A control technology is

considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of control effectiveness (percent pollutant removed). If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except, for the environmental analyses and any more stringent limits established from other RBLC Permits.

Step 4: Evaluate the Most Effective Controls and Document the Results
The fourth step begins with an evaluation of the remaining technologies under consideration for each pollutant of concern in regards to energy, environmental, and economic impacts for determining a final control technology. The highest ranked alternative is evaluated for environmental, energy and economic impacts specific to the proposed modification. If the analysis determines that the highest ranked control is not appropriate as BACT, due to any of the energy, environmental, and economic impacts, then the next most effective control is evaluated. The evaluation continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further economic or environmental analysis. In no case can the selected BACT be less stringent than any New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP) or Reasonably Available Control Technologies (RACT) standard or emission limit.

Step 5: Select BACT
The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible.

GHGs BACT – Natural Gas-Fired Boiler EU 028

Step 1: Identify Potential Control Technologies

GHG emissions from combustion consist primarily of carbon dioxide (CO_2) and very low emissions of methane (CH_4) and nitrous oxide (N_2O). Using each compound's global warming potential (GWP), the emissions are converted to CO2e. Since over 90 percent (%) of GHG emissions in this process come from CO_2, only control technologies for CO_2 will be considered in this analysis. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

(1) Carbon Capture and Storage (CCS);

(2) Carbon Transport and Sequestration;

(3) Energy Efficient Equipment;

(4) Low CO_2 Emitting Fuel;

(5) Good Design Operation, and Combustion Practices;

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) refers to the technology used to prevent the release of CO_2 emitted from fuel combustion processes by capturing, transporting, and pumping it into underground geologic formations. According to EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (*March 2011*), although CCS should be considered in the BACT assessment, it should be considered for large CO_2 emitters and sources with high-purity CO_2 streams such as power plants, hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing.

Low CO_2 levels are expected in the exhaust stream (typically 8 to 12 percent for natural gas) from this boiler. The source is not aware of any commercially available systems currently in place for this type of boiler and therefore considers this to be an undemonstrated technology.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon capture and storage is not a technically feasible option for the natural gas-fired Boiler at this source.

Carbon Transport and Sequestration

Carbon sequestration is a three step process that includes capturing CO_2 from exhaust streams, compressing the CO_2 and transporting it, usually via pipeline, to underground injection and geological sequestration sites. The compressed/pressurized CO_2 is injected into deep underground rock formations that are often a mile or more beneath the surface. The underground rock formations consist of multiple layers of porous rock that are underneath impermeable, non-porous layers of rock that trap the CO_2 and prevent it from migrating upward. The majority of rock formations considered for CO_2 sequestration are made up of sandstone, shale, basalt, or deep coal seams. Deep saline formations and depleted oil and gas reserves are also utilized frequently.

A well is drilled into the rock formation and then the compressed/pressurized CO_2 is injected into the rock. Under high pressure, the injected CO_2 turns to liquid and can move through a rock formation as a fluid. The liquid CO_2 tends to flow upward, where it encounters the non-porous rock layer that traps the fluid. When CO_2 is injected into coal seams, it is absorbed onto the coal surfaces and methane gas is released and produced in adjacent wells.

Carbon sequestration is considered a technically feasible option for the boiler; however this technology is not considered to be currently commercially available. This form of CO_2 control is being researched and investigated in Indiana, however it is not currently widely used and the success rate of such the control method has not yet been established. Furthermore, extensive piping would be needed to transport the compressed CO_2 to a sequestration site. Although there are proposed CO_2 pipelines in development in Indiana, none are currently constructed or operating. Permitting and environmental considerations make pipeline construction an unreliable option.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon transport and sequestration is not a technically feasible option for the natural gas-fired Boiler at this source.

Energy Efficient Equipment

Operating combustion units such as boilers with an optimum amount of excess air minimizes heat loss and improves combustion efficiency. Energy efficient designs for nearly all types of boilers and other combustion units are commercially available to reduce fuel consumption and, subsequently, greenhouse gas emissions.

High energy efficiency is expected from a new boiler that incorporates many of the technologies currently used to upgrade older boilers. These measures increase energy efficiency and reduce greenhouse gas emissions. Per the boiler's manufacturer, the new boiler is expected to be at least 84 percent efficient when it is first installed; therefore energy efficiency is expected to be the primary control technology option for the boiler.

As an example of these measures, the boiler will include a high efficiency economizer and will utilize flue gas recirculation. An economizer is a heat exchanger used to transfer some of the heat from the boiler exhaust gas to the incoming boiler feedwater. Preheating the feedwater reduces boiler heating load, increasing its thermal efficiency and reducing emissions. The boiler will also utilize 25 percent flue gas recirculation. When flue gas recirculation (FGR) is used, flue gas is diverted from a location downstream of the main boiler bank and is mixed with the combustion air from a forced draft fan. The recirculated flue gas acts as a heat sink, absorbing heat from the flame, lowering peak flame temperature, and reducing the oxygen content in the combustion air. Thus, FGR increases boiler efficiency and steaming capacity while decreasing nitrogen oxide emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of energy efficient equipment is a technically feasible option for the natural gas-fired Boiler at this source.

Low CO_2 Emitting Equipment

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Typically, solid fossil fuels such as bituminous coal have higher CO_2 emitting potential as compared to gaseous fuels such as natural gas.

Among the typical fuels currently used for boilers (coal, fuel oil, natural gas, etc.), the source will be using two of the lowest CO_2 emitting fuels, natural gas and biogas, in its new boiler. An alternative with lower emissions would be to use 100% biogas fuel; however, it is not yet clear how biogas fuels will be regulated under the GHG Tailoring Rule and potential GHG emissions would decrease by only 1.4% if biogas completely replaced natural gas. Furthermore, biogas has a lower higher heating value than natural gas; as a result, a significantly higher volume of biogas would be required to meet the mill's steam demand as compared to natural gas. The amount of biogas needed by the boiler would far exceed the amount of gas the wastewater treatment plant could generate.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Low CO_2 emitting fuel is a technically feasible option for the natural gas-fired Boiler at this source.

Good Design Operating, and Combustion Practices

Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods, procedures, and selection of raw materials to minimize emissions. An example of a good operating practice is the use of low VOC-emitting additives in the papermaking process. Good combustion practices typically include the following components: good air/fuel mixing in the combustion zone, high temperatures and low oxygen levels in the primary combustion zone, overall excess oxygen levels high enough to complete combustion while maximizing efficiency, and sufficient residence time to complete combustion.

The use of good operating practices, such as following the boiler manufacturer's Operation and Maintenance Manual, and good combustion practices would ensure the boiler is operating as efficiently as possible and therefore minimize CO_2 emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Design Operating, and Combustion Practicesis a technically feasible option for the natural gas-fired Boiler at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling GHG emissions from the Natural gas-fired Boiler.

(1) Use of low CO_2 emitting fuel;
(2) Energy Efficient Boiler
(3) Good Operating and Combustion Practices;

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO_2e BACT determination along with the existing CO_2e BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Jet Corr, Inc, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies. All limitations in parenthesis were not obtained from the RBLC but were calculated to provide a consistent basis for comparing emissions rates to the proposed project.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (MMBtu/hr)**	**Limitation**	**Control Method**
Draft Permit No. 127-33729-00094 Proposed Limit	**Jet Corr, Inc - *proposed***	**Proposed**	**Natural Gas-Fired Boiler (EU 028)**	**350 MMBtu/hr**	**Use of natural gas and biogas fuels with 117 lbs CO_2 per MMBtu**	**Good Operating and Combustion Practice**
IA-0105	Iowa Fertilizer Company	10/26/2012	Auxiliary Boiler	472.4 MMBtu/hr	NA	Good Combustion Practices
TX-0629	BASF Total Petrochemicals LP	08/24/2012	Ethylene Cracking Furnace No.10	498 MMBtu/hr	NA	Selective Catalytic Reduction System
IA-0105	Iowa Fertilizer Company	10/26/2012	Startup Heater	110.12 MMBtu/hr	NA	Good Combustion Practices
TX-0629	BASF Total Petrochemicals LP	08/24/2012	Gas Turbine Auxiliary Duct Burners	310.4 MMBtu/hr	NA	Selective Catalytic Reduction System
CA-1212	Palmdale Hybrid Power Project	10/18/2011	Auxiliary Boiler	110 MMBtu/hr	NA	Annual Boiler Tune -ups
LA-0260	Ethylene Plant	4/11/2011	Cracking Furnace 95 and 96	180 MMBtu/hr	NA	1. Low-emitting feedstocks, 2.energy efficient equipment,

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
						3. Process design improvement, 4. Low-emitting and low carbon fuel (>25 vol% hydrogen, annual ave)

The technically feasible options for controlling CO_2 emissions from the new boiler are using a low CO_2 emitting fuel, energy efficiency, and good operating and combustion practices.

The source is proposing to use only natural gas and biogas generated from the wastewater treatment plant as fuels in the boiler. In comparison to other fossil fuels, these are low CO_2 emitting fuels; per 40 CFR Part 98 (Mandatory Greenhouse Gas Reporting Rule), Subpart C (General Stationary Fuel Combustion Sources):

- Natural gas – pipeline (weighted national average) = 117 lbs CO_2/MMBtu
- Biomass Fuels - Biogas (captured methane) = 115 lbs CO_2/MMBtu
- Distillate Oil (No. 2) = 163 lbs CO_2/MMBtu
- Bituminous Coal = 206 lbs CO_2/MMBtu
-

According to the Council of Industrial Boiler Operators (CIBO) – *Energy Efficiency & Industrial Boiler Efficiency, An Industry Perspective – March 2003*, the typical efficiency for a new natural gas boiler ranges from 70 percent at low load to 75 percent at full load. The proposed boiler is rated at 350.05 MMBtu/hr and, according to the manufacturer's specifications, the efficiency of the unit will be approximately 84 percent. A good maintenance program will ensure that performance will not deteriorate greatly with time. The resulting boiler efficiency, assuming ten percent deterioration over time, would be 74 percent.

Proposal: **Jet Corr, Inc** – **Valparaiso, Indiana**
The following has been proposed as BACT for GHG emissions from the proposed natural gas-fired boiler:

(1) The use of natural gas and biogas only,

(2) Implementation of an energy efficient design

(3) Good operating and combustion practices; and

(4) The total CO_2 emissions from the natural gas-fired boiler shall not exceed 179,392 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Natural Gas-Fired Boiler, identified as EU 025:

(1) The use of natural gas and biogas only,

(2) Implementation of an energy efficient design

(3) Good operating and combustion practices;

(4) Boiler designed for 74% thermal efficiency (HHV);

(5) The emission rate shall not exceed 117 lbs CO2 per MMBtu/hour; and

(6) The total CO_2 emissions from the natural gas-fired boiler shall not exceed 179,392 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Greenhouse Gases (GHG) BACT – Biogas Flare EU 025

Step 1: Identify Potential Control Technologies

GHG emissions from combustion consist primarily of carbon dioxide (CO_2) and very low emissions of methane (CH_4) and nitrous oxide (N_2O). Using each compound's global warming potential (GWP), the emissions are converted to CO_2e. Since over 90 percent (%) of GHG emissions in this process come from CO_2, only control technologies for CO_2 will be considered in this analysis. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

GHG control possibilities identified and addressed in this BACT analysis for the Biogas Flare are as follows:

(1) Carbon Capture and Storage (CCS);

(2) Carbon Transport and Sequestration;

(3) Good Design Operation, and Combustion Practices;

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) refers to the technology used to prevent the release of CO_2 emitted from fuel combustion processes by capturing, transporting, and pumping it into underground geologic formations. According to EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (*March 2011*), although CCS should be considered in the BACT assessment, it should be considered for large CO_2 emitters and sources with high-purity CO_2 streams such as power plants, hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing.

Low CO_2 levels are expected in the exhaust stream from this flare. The source is not aware of any commercially available systems currently in place for this type of flare and therefore considers this to be an undemonstrated technology.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon capture and storage is not a technically feasible option for the biogas flare at this source.

Carbon Transport and Sequestration

Carbon sequestration is a three step process that includes capturing CO_2 from exhaust streams, compressing the CO_2 and transporting it, usually via pipeline, to underground injection and geological sequestration sites. The compressed/pressurized CO_2 is injected into deep underground rock formations that are often a mile or more beneath the surface. The underground rock formations consist of multiple layers of porous rock that are underneath

impermeable, non-porous layers of rock that trap the CO_2 and prevent it from migrating upward. The majority of rock formations considered for CO_2 sequestration are made up of sandstone, shale, basalt, or deep coal seams. Deep saline formations and depleted oil and gas reserves are also utilized frequently.

A well is drilled into the rock formation and then the compressed/pressurized CO_2 is injected into the rock. Under high pressure, the injected CO_2 turns to liquid and can move through a rock formation as a fluid. The liquid CO_2 tends to flow upward, where it encounters the non-porous rock layer that traps the fluid. When CO_2 is injected into coal seams, it is absorbed onto the coal surfaces and methane gas is released and produced in adjacent wells.

Carbon sequestration is considered a technically feasible option for the flare; however this technology is not considered to be currently commercially available. This form of CO_2 control is being researched and investigated in Indiana, however it is not currently widely used and the success rate of such the control method has not yet been established. Furthermore, extensive piping would be needed to transport the compressed CO_2 to a sequestration site. Although there are proposed CO_2 pipelines in development in Indiana, none are currently constructed or operating. Permitting and environmental considerations make pipeline construction an unreliable option.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon transport and sequestration is not a technically feasible option for the biogas flare at this source.

Good Design Operating, and Combustion Practices
Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods, procedures, and selection of raw materials to minimize emissions. An example of a good operating practice is the use of low VOC-emitting additives in the papermaking process. Good combustion practices typically include the following components: good air/fuel mixing in the combustion zone, high temperatures and low oxygen levels in the primary combustion zone, overall excess oxygen levels high enough to complete combustion while maximizing efficiency, and sufficient residence time to complete combustion.

Anaerobic digester systems typically produce biogas that is comprised of methane and CO_2, as well as many trace gases. As is the case with Pratt, the methane rich biogas is often collected and used as a fuel. Biogas flares are utilized in anaerobic digester systems to address the issue of biogas production in the event of a system shutdown or malfunction or a surplus of gas production. The flare will be designed to adequately control the collected biogas in the event it is not sent to the boiler. Therefore good design practices are considered technically feasible.

Greenhouse gas emissions from the flare are due to the combustion of the biogas; the open combustion nature of flares allows for good oxidation of methane and thus reduces GHG emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good design operating, and combustion practices is a technically feasible option for the biogas flare at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are;

(1) Good Design Operating, and Combustion Practices;

Step 4: Evaluate the Most Effective Controls and Document the Results

An RBLC search found no control requirements for CO_2 or CO_2e for biogas flares. The biogas flare will be designed and operates so as to meet the requirements of 40 CFR 60.18(b). As such, the proposed BACT for the flare is in compliance with the requirements of the General Provisions of the Standards of Performance for New Stationary Sources.

Proposal: **Jet Corr, Inc** – **Valparaiso, Indiana**
The followings have been proposed as BACT for GHG from the proposed Biogas Flare, identified as EU 025:

(1) Good Design Operating, and Combustion Practices; and

(2) The total CO_2e emissions for Biogas flare shall be limited to less than 3,825 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHGs for the Biogas Flare, identified as EU 025.

(1) Good Design Operating, and Combustion Practices; and

(2) The total CO_2 emissions for Biogas flare shall be limited to less than 3,825 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

GHGs BACT – Emergency Fire Pump EU 027

Step 1: Identify Potential Control Technologies

GHG emissions from combustion consist primarily of carbon dioxide (CO_2) and very low emissions of methane (CH_4) and nitrous oxide (N_2O). Using each compound's global warming potential (GWP), the emissions are converted to CO_2e. Since over 90 percent (%) of GHG emissions in this process come from CO_2, only control technologies for CO_2 will be considered in this analysis. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

GHG control possibilities identified and addressed in this BACT analysis for the emergency fire pump are as follows:

(1) Good engineering design and Fuel efficient design; and

(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options

Good Engineering Design and Fuel Efficient Design
Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods, procedures, and selection of raw materials to minimize emissions. An

example of a good operating practice is the use of low VOC-emitting additives in the papermaking process. Good combustion practices typically include the following components: good air/fuel mixing in the combustion zone, high temperatures and low oxygen levels in the primary combustion zone, overall excess oxygen levels high enough to complete combustion while maximizing efficiency, and sufficient residence time to complete combustion.

The emergency fire pump's generator will be designed to combust diesel fuel only. The chemical structure of diesel fuel allows it to release more energy per unit than other common liquid fuel sources such as gasoline. Greater energy output means less fuel consumption than other sources of fuel. Furthermore, the generator will be operated in a manner that meets the operation and work practice requirements of 40 CFR Part 63, Subpart ZZZZ (RICE MACT).

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good engineering design and fuel efficient design is a technically feasible option for the emergency fire pump at this source.

Carbon Capture

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The source combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. In this US EPA, carbon capture isn't listed or considered in the BACT analysis as a potentially available option for emergency fired engines. The absence of a discussion of carbon capture for emergency engines is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the source's Project miscellaneous combustion sources are an order of magnitude smaller than EPA's example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the emergency diesel engines is not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon capture of CO_2 is not a technically feasible option for the emergency fire pump at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the fire pump diesel engines is;

(1) Good engineering design and Fuel Efficient Design.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO_2e BACT determination along with the existing CO_2e BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Jet Corr, Inc, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies. All limitations in parenthesis were not obtained from the RBLC but were calculated to provide a consistent basis for comparing emissions rates to the proposed project.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
Draft Permit No. 127-33729-00094 Proposed Limit	**Jet Corr, Inc - *proposed***	**Proposed**	**Emergency Fire Pump (EU 027)**	**183 HP**	**Use of diesel fuel only**	**Good engineering design and Fuel Efficient Design**
LA-0254	Ninemile Point Electric Generating Plant	08/16/2011	Emergency Diesel Generator	1250 HP	NA	Proper Operating and Good Combustion Practices
LA-0254	Ninemile Point Electric Generating Plant	08/16/2011	Emergency Fire Pump	350 HP	NA	Proper Operating and Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/2012	Emergency Diesel Generator	142 gal/hr	NA	Good Combustion Practices
IA-0105	Iowa Fertilizer Company	10/26/2012	Emergency Fire Pump	14 gal/hr	NA	Good Combustion Practices
IN-0158	St. Joseph Energy Center, LLC	12/03/2012	Two (2) Firewater Pump Diesel Engines	371 BHP, each	NA	Good Engineering design and fuel efficient design
IN-0158	St. Joseph Energy Center, LLC	12/03/2012	Two (2) Emergency Diesel Generators	1006 HP, each	NA	Good Engineering design and fuel efficient design

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
IN-0158	St. Joseph Energy Center, LLC	12/03/2012	Emergency Diesel Generator	2012 HP	NA	Good Engineering design and fuel efficient design
OH-0352	Oregon Clean Energy Center	06/18/2013	Emergency Fire Pump Engine	300 HP	NA	NA
OH-0352	Oregon Clean Energy Center	06/18/2013	Emergency Generator	2250 KW	NA	NA
TX-0612	Thomas C. Ferguson Power Plant	11/10/2011	EMGEN1-SK-Diesel-Fired Emergency Generator	93.8 HP	NA	NA
TX-0612	Thomas C. Ferguson Power Plant	11/10/2011	FWP1-STK- Diesel-Fired Water Pump	617 HP	NA	Best Practices
VA-0319	Gateway Cogeneration 1, LLC-Smart Water Project	08/27/2012	Fire Water Pump	1.86 MMBtu/hr	NA	Fuel efficient design
PA-0291	Hickory Run Energy Station	04/23/2013	Emergency Firewater Pump	3.25 MMBtu/hr	NA	NA
PA-0291	Hickory Run Energy Station	04/23/2013	Emergency Generator	7.8 MMBtu/hr	NA	NA

The following has been proposed as BACT for GHG emissions from the proposed Emergency Fire Pump engine: the selection and use of good engineering design and fuel efficient design.

This project includes one (1) diesel-fired standby fire pump. The engine is expected to operate less than 500 hours per year each. That use is associated with assuring their readiness in an emergency. This emergency diesel engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel. However, because the normal use is limited to routine maintenance, inspection and testing, the total emissions are very small (less than 100 tons CO_2e/yr).

The source proposing to only use the Emergency Fire Pump during emergency situations and for routine maintenance and testing in such a way so as to meet the requirements of RICE MACT. Furthermore, only diesel fuel will be utilized in the fire pump's generator.

Proposal: **Jet Corr, Inc** – **Valparaiso, Indiana**

The following has been proposed as BACT for GHG emissions from the proposed Emergency Fire Pump, identified as EU 027:

(1) The use of a good engineering design and Fuel Efficient Design;

(2) The use of diesel fuel only; and

(3) The total CO_2 emissions from the emergency fire pump engine shall be limited to less than 19 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the Emergency Fire Pump Engine, identified as EU 027:

(1) The use of a good engineering design and Fuel Efficient Design;

(2) The use of diesel fuel only; and

(3) The total CO_2 emissions from the emergency fire pump engine shall be limited to less than 19 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Greenhouse Gases (GHG) BACT – Miscellaneous Natural Gas-Fired Units EU 030

Step 1: Identify Potential Control Technologies

GHG emissions from combustion consist primarily of carbon dioxide (CO_2) and very low emissions of methane (CH_4) and nitrous oxide (N_2O). Using each compound's global warming potential (GWP), the emissions are converted to CO_2e. Since over 90 percent (%) of GHG emissions in this process come from CO_2, only control technologies for CO_2 will be considered in this analysis. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

GHG control possibilities identified and addressed in this BACT analysis for the miscellaneous natural gas-fired units are as follows:

(1) Carbon Capture and Storage (CCS);

(2) Carbon Transport and Sequestration;

(3) Low CO_2 Emitting Fuel

(4) Good Design Operation, and Combustion Practices;

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The small combustion sources such as the natural gas units do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired unit. In this US EPA example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

The absence of a discussion of carbon capture in this 250 MMBtu/hr natural gas example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2

sources. In stark contrast, this Project miscellaneous combustion source only uses 10 MMBtu/hr. As such it is two orders of magnitude smaller than EPA's boiler example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the natural gas units are not a reasonable BACT option because the capture of the CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon capture and storage (CCS) of CO_2 is not a technically feasible option for the natural gas-fired units at this source.

Carbon Transport and Sequestration
Carbon sequestration is a three step process that includes capturing CO_2 from exhaust streams, compressing the CO_2 and transporting it, usually via pipeline, to underground injection and geological sequestration sites. The compressed/pressurized CO_2 is injected into deep underground rock formations that are often a mile or more beneath the surface. The underground rock formations consist of multiple layers of porous rock that are underneath impermeable, non-porous layers of rock that trap the CO_2 and prevent it from migrating upward. The majority of rock formations considered for CO_2 sequestration are made up of sandstone, shale, basalt, or deep coal seams. Deep saline formations and depleted oil and gas reserves are also utilized frequently.

A well is drilled into the rock formation and then the compressed/pressurized CO_2 is injected into the rock. Under high pressure, the injected CO_2 turns to liquid and can move through a rock formation as a fluid. The liquid CO_2 tends to flow upward, where it encounters the non-porous rock layer that traps the fluid. When CO_2 is injected into coal seams, it is absorbed onto the coal surfaces and methane gas is released and produced in adjacent wells.
Carbon sequestration is considered a technically feasible option for the natural gas units; however this technology is not considered to be currently commercially available. This form of CO_2 control is being researched and investigated in Indiana, however it is not currently widely used and the success rate of such the control method has not yet been established. Furthermore, extensive piping would be needed to transport the compressed CO_2 to a sequestration site. Although there are proposed CO_2 pipelines in development in Indiana, none are currently constructed or operating. Permitting and environmental considerations make pipeline construction an unreliable option.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of carbon transport and sequestration is not a technically feasible option for the natural gas-fired units at this source.

Low CO_2 Emitting Fuel
Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Typically, solid fossil fuels such as bituminous coal have higher CO_2 emitting potential as compared to gaseous fuels such as natural gas. Among the typical fuels currently used for natural gas units (coal, fuel oil, natural gas, etc.), the source will be using the lowest CO_2 emitting fuels such as

natural gas. These units will combust natural gas only, which is one of the lowest GHG emitting fuel.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Low CO_2 emitting fuel is a technically feasible option for the natural gas-fired units at this source.

Good Design Operating, and Combustion Practices
Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods, procedures, and selection of raw materials to minimize emissions. An example of a good operating practice is the use of low VOC-emitting additives in the papermaking process. Good combustion practices typically include the following components: good air/fuel mixing in the combustion zone, high temperatures and low oxygen levels in the primary combustion zone, overall excess oxygen levels high enough to complete combustion while maximizing efficiency, and sufficient residence time to complete combustion.

The combustion of natural gas is inherently efficient, and good engineering design of the burner will assure efficient combustion.

The use of good operating practices, such as following the emission units manufacturer's Operation and Maintenance Manual, and good combustion practices would ensure the natural gas units are operating as efficiently as possible and therefore minimize CO_2 emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good design operating, and combustion practices is a technically feasible option for the natural gas-fired units at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are;

(1) Low CO_2 emitting Fuel

(2) Good design operating and Combustion Practices; and

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO_2e BACT determination along with the existing CO_2e BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Jet Corr, Inc, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies. All limitations in parenthesis were not obtained from the RBLC but were calculated to provide a consistent basis for comparing emissions rates to the proposed project.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
Draft Permit No. 127-33729-00094 Proposed Limit	**Jet Corr, Inc - *proposed***	**Proposed**	**Natural Gas-Fired Units (EU 030)**	**10 MMBtu/hr**	**Use of natural gas**	**Good design Operating and Combustion Practice**
SC-0142	Showa Denko Carbon , Inc	08/11/2011	Hot Oil Heater	5 MMBtu/hr	NA	Good Combustion Practices, Anual Tune up and Low NOx Burners
SC-0142	Showa Denko Carbon , Inc	08/11/2011	Pitch Impregnation/ Preheater	12 MMBtu/hr	NA	Good Combustion Practices, Annual Tune up and Low NOx Burners
SC-0142	Showa Denko Carbon , Inc	08/11/2011	Carbottom Furnace	18 MMBtu/hr	NA	Thermal oxidizer, Low NOx, Burners, Good Combustion Practices, Annual Tune up and Process Optimization
IN-0166	Indiana Gasification, LLC	06/27/2012	Five (5) Gasifier Preheater Burners	35 MMBtu/hr	NA	Use of Good Engineering Design, the use of natural gas or SNG
IN-0167	Magnetation, LLC	04/16/2013	Space Heaters	1 MMBtu/hr	NA	Use of Natural Gas and Good Combustion Practices
IN-0167	Magnetation, LLC	04/16/2013	Coke Breeze Additive System Air Heater	1.7 MMBtu/hr	NA	Use of Natural Gas and Good Combustion Practices

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (MMBtu/hr)	Limitation	Control Method
GA-0147	Pyramax Ceramics, LLC - King's M:U Facility	01/27/2012	Boilers	9.8 MMBtu/hr	NA	Good Combustion Practices, design and thermal insulation
IN-0167	Magnetation, LLC	04/16/2013	Ground Limestone/Dolomite Additive System Air Heater	19 MMBtu/hr	NA	Use of Natural Gas and Good Combustion Practices
CA-1212	Palmdale Hybrid Power Project	08/19/2011	Auxiliary Heater	40 MMBtu/hr	NA	Annual Boiler Tune -ups

Based on a review of the RBLC and other Indiana permits, the primary control used for miscellaneous natural gas-fired units is the use of good combustion practices. Thus, the source is suggesting the use of natural gas only and good combustion practices as BACT for these units.

Proposal: **Jet Corr, Inc** – **Valparaiso, Indiana**

The following has been proposed as BACT for GHG from the proposed Natural Gas-Fired Units EU 030:

(1) Good design operating and Combustion Practices;

(2) The use of only natural gas; and

(3) The total CO_2 emissions for Natural Gas-Fired Units shall be limited to less than 5,125 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHGs for the Natural Gas-Fired Units, identified as EU 030.

(1) Good design operating and Combustion Practices;

(2) The use of only natural gas: and

(3) The total CO_2 emissions for Natural Gas-Fired Units shall be limited to less than 5,125 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of each month.

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)

Requirement for Best Available Control Technology (BACT), 326 IAC 8-1-6

The requirements of 326 IAC 8-1-6 (New Facilities, General Reduction Requirements) applies to facilities located anywhere in the state that are constructed on or after January 1, 1980, which have potential volatile organic compounds (VOC) emissions greater than 25 tons per year, and which are not otherwise regulated by other provisions of 326 IAC 8 rule, and requires the reduction of VOC emissions using Best Available Control Technology (BACT). The proposed Paper Machine, identified as EU 029 has potential VOC emissions of greater than 25 tons per year and is therefore subject to the requirements of this rule.

326 IAC 8-1-6 requires a best available control technology (BACT) review to be performed on the proposed new emission unit:

(1) One (1) paper machine designed to produce linerboard and medium from waste paper, identified as EU 029, permitted in 2014, with a maximum throughput of 1600 tons of air dried finished product per day and exhausting to stack S 029.

Volatile Organic Compounds (VOCs) BACT - Paper Machine EU 029

Step 1: Identify Potential Control Technologies

The volatile organic compounds (VOC) emissions can be controlled by the following methods:

(1) Oxidation Systems;

(2) Adsorption Systems;

(3) Absorption Systems;

(4) Biofiltration Systems.

(5) Condensation Systems; and

(6) Good Design and Operating Practices.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable in reducing VOC emissions. The control technologies listed in the previous section are discussed and evaluated below for their technical feasibility.

Oxidation Systems

Oxidation refers to the combustion of organic compounds at a sufficiently high temperature and adequate residence time. Oxidation systems can be categorized as either thermal or catalytic. These categories can be further divided based on the type of heat recovery used. If a shell-and-tube or plate-type heat exchange is used, the system is generally classified as recuperative. If a high-efficiency bed of ceramic material is used, the system is generally classified as regenerative.

Catalytic oxidation systems are subject to fouling and masking from various chemical agents. These chemicals could act as catalyst poisons or fouling agents and could make the use of a catalytic oxidation system infeasible. Regardless, oxidation systems are technically feasible forms of control for the paper machine, boiler and emergency fire pump. This type of control is considered technically impractical for sources that emit VOCs in a concentration less than 1 ppmv.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of oxidation system is a technically feasible option for Paper Machine (EU 029) at this source.

Adsorption Systems

Adsorption is the process by which molecules collect on and adhere to the surface of an adsorbent solid. This adsorption is due to physical and/or chemical forces. Activated carbon is typically used as an adsorbent because of its large surface area, which is a critical factor in the adsorption process. The adsorption capacity of a material is proportional to surface area; activated carbon has significant surface area due to its internal pore structure. Carbon adsorption systems are ideally used for recoverable VOC materials.

The captured exhaust from paper making operations would contain a complex and highly variable mixture of volatile compounds. This mixture of chemical components would limit the effectiveness of the carbon used in the adsorption system due to interactions between chemical components, preferential adsorption of certain chemical components by the carbon, and resulting premature breakthrough of remaining chemical components.

Activated carbon would not be a reliable control technology for the highly variable VOC exhaust stream from the paper machine. Additionally, exhaust streams need to be routed directly into the adsorption system. Therefore, adsorption systems would be considered technically impractical for controlling the exhaust of the paper machines and fugitive sources.

Adsorption will be considered technically feasible method for VOC control from the remaining non-fugitive VOC emitting sources at the mill. Cost calculations for this application can be found in later sections of this report.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an adsorption system is not a technically feasible option for Paper Machine (EU 029) at this source.

Absorption Systems

In adsorption systems, certain constituents of a gas stream are selectively removed by a liquid solvent. The control of gas-phase VOCs using an absorption scrubber system relies on contact between the contaminated gas and a liquid in which the contaminants are soluble or with which it will chemically react. The degree of control depends on the following:

- Solubility of the gas;
- Gas and liquid throughput rates;
- Contact time;
- Mechanism of contact; and
- Type of scrubber.

Low concentrations of organics in an exhaust stream require long contact times and large quantities of absorbent for effective removal. Absorptions in generally more practical for

processes in which the absorbent is easily regenerated or the resulting solution can be used as a make-up stream.

Typically, on a mass basis, only about 50% of the total VOCs emitted from papermaking operations and 4 percent of VOCs emitted from natural gas combustion are soluble. The remaining VOCs are insoluble or only slightly soluble in water. The potential concentration of all water soluble VOCs expected in the paper machine exhaust stream is approximately 120 ppmv.

Low gas-phase concentrations would require an unreasonable high water throughput rate and/or an inordinately large scrubber to support sufficient contact time. Therefore, for the purposes of this BACT analysis, absorption systems will be considered technically impractical for all units.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an absorption systems is not a technically feasible option for Paper Machine (EU 029) at this source.

Biofiltration Systems

Biofiltration is based on the biodegradation of exhaust stream constituents as the exhaust passes through a biologically active filter material. This technology is a very complex process and has had limited use in the United States. Currently, most applications of this process are for odor control in composing operations.

The bacteria commonly used in biofiltration are susceptible to damage by broadly varying process conditions such as those that can be expected from paper making operations. Biofiltration is an innovative technology and, while some vendors are beginning to offer these services, it would require additional testing and evaluation to confirm its technical feasibility for the units at the proposed mill. Questions and additional testing needed before biofiltration is developed into an optimized technology include: understanding the kinetics of biodegradation of the specific organic compounds in the gas stream, the effect of different packing materials and microbial cultures, and realistic modeling of the process.

Regardless of the limitations associated with this control type, we have prepared a cost analysis based on the assumption that it is technically feasible for sources emitting VOCs in a concentration greater than 1 ppmv.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Biofiltration is a technically feasible option for Paper Machine (EU 029) at this source.

Condensation Systems

Condensation systems utilize a refrigeration source to cool the exhaust stream to convert the VOC from a gaseous phase to a liquid phase. Often, condensation is used in combination with other control methods. When used alone, high-recovery efficiencies (greater than 95 percent) using condensation can be achievable for concentrations greater than 5,000 ppmv.

All sources of VOCs at the new recycle mill have exhaust stream VOC concentrations well below 5,000 ppmv; thus condensation is not considered a technically feasible control method for any of the VOC emitting units at the mill.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a condensation system is not a technically feasible option for Paper Machine (EU 029) at this source.

Good Design and Operating Practices

Good design includes process and mechanical equipment designs which are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods and procedures and selection of raw materials to minimize emissions. Good design and operating practices are feasible control methods for all sources at the mill.

The overall flow rate of this stream is very high, but VOC concentrations are low. As such, the heating value of the stream is too low for effective destruction in a flare. Since there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control effectiveness versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a good design and operating practices is a technically feasible option for Paper Machine (EU 029) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling VOC emissions from the Paper Machine EU-029.

(1) Oxidation System (98% VOC Reduction)

(2) Biofiltration (95% VOC Reduction)

(3) Good Design and operating practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by Jet Corr, Inc, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
Draft Permit No. 127-33729-00094 Proposed Limit	**Jet Corr, Inc - *proposed***	**Proposed**	**Paper Machine (EU 029)**	**1600 tons of air dried paper per day**	**0.24 lb VOC/Air Dried Tons of Finished Product**	**Good design and Operating Practice**
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #3	850 machine dried ton/day	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-	05/31/2007	Fine Paper	1050 machine	NA	The facility also proposes that its new substance

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
	Pacific Corporation Crossett Paper Operation		Machine #1 and #2	dried ton/day		review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #4	173 machine dried ton/day	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #5	97 machine dried ton/day	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #6	270 machine dried ton/day, 30-day ave	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #7	250 machine dried ton/day, 30-day ave	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
AR-0099	Georgia-Pacific Corporation Crossett Paper Operation	05/31/2007	Paper Machine #8	212 machine dried ton/day, 30-day ave	NA	The facility also proposes that its new substance review program be considered BACT. The mill will utilize a lower VOC-containing chemical whenever one is available as a substitute for the chemical being used.
LA-0205	Louisiana Mill	11/20/2003	Paper Machine #1 and #2	136200 SWT/Year, each	Mass emission limit for paper machines (ID Cap-PM) set at 183.8 lbs/he (Hourly Maximum) and 185.9 tons per yr (Annual Maximum)	NA

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating	Limitation	Control Method
WA-0303	Longview Fibre Paper and Packaging, Inc	11/1/2006	Paper Machine	NA	Alternate Control Technologies were regenerative thermal oxidation and exhaust duct burner, effective cost were $46,000/T and $22,000/T respectively	Use of Low VOC Additives, there is no associated permit limit on VOC emissions. Anticipated net emissions increase is 72.5 tons/yr
WI-0216	Appleton Coated-Combined Locks Mill	6/8/2004	Paper Machine #6 (S62A, P62A)	498 ADT/Day	(A) Total VOC contained within coating and any other materials/Additives used on the machine, shall not exceed 1.4 lbs VOC per ton of paper produced on a 12 month rolling average basis, for all additives combined. [S.285.65(7), WIS. STATS., S.NR 405.08 and S.NR0424.03(2) WIS.ADM.CODE] (B) Retention Aids used on the machine may not contain more than 36 wt% VOC [S.285.65(7), WIS. STATS., S.NR 405.08 and S.NR0424.03(2) WIS.ADM.CODE] (C) Pulp used on this machine shall be purchased pulp, broke or other dried fiber material containing minimal VOC's. The Pulp Stock may not be subsequently bleached in a fashion which produces or introduces VOCs	Limits on the raw materials VOC additives and use of market pulp

To complete the BACT review for VOC emissions, it must be determined if the individual stacks, or groups of stacks may be expected to have higher concentrations or higher overall quantities of emissions when compared to the overall paper machine to determine if control of a portion of the operation may be economically feasible. Higher concentrations and emission rates tend to make add-on control equipment more cost-effective. The facility will be a new construction; therefore no stack testing data is available to allocate potential emissions between stack groups. For this BACT analysis, IDEM assumed two stack groupings, stacks located at the wet end of the paper machine and stacks located at the dry end of the paper machine. It was further assumed that 60% of total VOC emissions would be emitted from the dry end and the remaining 40% emitted from the wet end. Accordingly, the ventilation systems and emission rates have been distributed to the two stack groupings.

Paper Machine Stack Groupings

Stack Grouping	Airflow Rate (acfm)	VOC Emission Rate (tons per year)
Wet End Only	50,000	28.27
Dry End Only	100,000	42.40
All Sources	150,000	70.66

The stack information is based on engineering judgment for the proposed paper machine. For this analysis, it was assumed the exhaust fans or blowers associated with each exhaust point operate at maximum capacity at all times during the operation of the paper machine.

The Table below presents a summary of the economic evaluation conducted for each type of add-on control that was determined to be technically feasible or practical for the paper machine. The evaluation was conducted for each of the stack groupings, as well as for the overall paper machine. Appendix C- Cost Analysis contains supporting calculations.

Summary of Estimated VOC Control Costs and Cost Effectiveness for the Paper Machine

Control Option	Total Capital Investment	Total Annualized Cost ($/year)	Cost Effectiveness ($/Ton of VOC)
All Sources			
Catalytic Regenerative Oxidation	$6,854,094	$2,978,564	$44,370
Catalytic Recuperative Oxidation	$3,140,096	$3,795,550	$56,540
Thermal Regenerative Oxidation	$5,470,774	$3,591,376	$53,498
Thermal Recuperative Oxidation	$1,343,884	$5,342,181	$79,579
Biofiltration	$10,841,395	$2,030,806	$30,251
Wet End Sources			
Catalytic Regenerative Oxidation	$2,780,865	$1,126,796	$41,963
Catalytic Recuperative Oxidation	$1,711,073	$1,424,327	$53,043
Thermal Regenerative Oxidation	$2,319,635	$1,331,450	$49,584
Thermal Recuperative Oxidation	$1,021,072	$1,926,172	$71,732
Biofiltration	$3,680,365	$748,069	$27,859
Dry End Sources			
Catalytic Regenerative Oxidation	$4,817,394	$2,054,968	$51,019
Catalytic Recuperative Oxidation	$2,510,032	$2,624,822	$65,167
Thermal Regenerative Oxidation	$3,895,104	$2,463,225	$61,155
Thermal Recuperative Oxidation	$1,214,384	$3,641,109	$90,398
Biofiltration	$7,261,130	$1,389,438	$34,496

The result of this review is that the use of add on control equipment to reduce VOC emissions from the entire paper machine, or a portion thereof, is beyond the range generally considered economically reasonable.

The additives used in the paper making process include, but are not limited to, biocides, dyes, polymers, defoamers, sizing agents, and felt washes. Based on a review of material safety data sheets, the majority of the materials to be used by the source are water based and/or contain low levels of VOCs. Based on a review of the RBLC and other Indiana permits, good operating practices such as the use of low VOC additives is the primary control method used for paper machines; however many facility have no control methods. Therefore, the paper machine without the use of add-on controls is proposed as BACT. This determination is supported by the RBLC search where no entries were found where add-on VOC emission control was considered viable for paper machines.

Proposal: **Jet Corr, Inc** – **Valparaiso, Indiana**

The following has been proposed as BACT for VOC from the proposed Paper Machine, identified as EU 029:

(1) Good design and Operating Practices.

Step 5: Select BACT

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), IDEM has established the following as BACT for VOC for Paper Machine, identified as EU 029.

(1) The use of good design and Operating Practices to limit the Volatile Organic compounds (VOC) emissions; and

(2) The VOC emissions shall not exceed 0.24 lb VOC/Air Dried Tons of Finished Product; and

(3) The throughput of air dried finished product to the Paper machine shall not exceed 584,000 tons per twelve (12) consecutive month period with compliance determined at the end of the month.

Scenario 2: Paper Machine

Estimated VOC Control Rate (TPY)	Control Option	Control Efficiency	Total Capital Investment	Total Annualized Cost	Cost Effectiveness ($/ton VOC)
70.314	Catalytic Regenerative Oxidation	95%	$6,854,094	$2,978,564	$44,370
	Catalytic Recuperative Oxidation	95%	$3,140,096	$3,795,550	$56,540
	Thermal Regenerative Oxidation	95%	$5,470,774	$3,591,376	$53,498
	Thermal Recuperative Oxidation	95%	$1,343,884	$5,342,181	$79,579
	Biofiltration	95%	$10,841,395	$2,030,806	$30,251

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0

Scenario 9: Paper Machine - Wet End Only

Estimated VOC Control Rate (TPY)	Control Option	Control Efficiency	Total Capital Investment	Total Annualized Cost	Cost Effectiveness ($/ton VOC)
28.125	Catalytic Regenerative Oxidation	95%	$2,780,865	$1,126,796	$41,963
	Catalytic Recuperative Oxidation	95%	$1,711,073	$1,424,327	$53,043
	Thermal Regenerative Oxidation	95%	$2,319,635	$1,331,450	$49,584
	Thermal Recuperative Oxidation	95%	$1,021,072	$1,926,172	$71,732
	Biofiltration	95%	$3,680,365	$748,069	$27,859

0
0

Scenario 10: Paper Machine - Dry End Only

Estimated VOC Control Rate (TPY)	Control Option	Control Efficiency	Total Capital Investment	Total Annualized Cost	Cost Effectiveness ($/ton VOC)
42.188	Catalytic Regenerative Oxidation	95%	$4,817,394	$2,054,968	$51,019
	Catalytic Recuperative Oxidation	95%	$2,510,032	$2,624,822	$65,167
	Thermal Regenerative Oxidation	95%	$3,895,104	$2,463,225	$61,155
	Thermal Recuperative Oxidation	95%	$1,214,384	$3,641,109	$90,398
	Biofiltration	95%	$7,261,130	$1,389,438	$34,496

STEP #1: Establish design specifications

Variable		Value
Scenario 2: Paper Machine	Scenario	2
Preheater Inlet Waste Gas Volume Flow Rate, scfm		120,968
Preheater Inlet Waste Gas Temperature, F		150
VOC Content, lbs/hr		16.053
Relative Humidity, %		30
Overall Control Efficiency, %		95

STEP #2: Enter exhaust composition data

Composition: CAS No.	Chemical Name	Actual VOC (lbs/hr)	Total VOC Weighted (lbs/hr)	Total Emissions (ppmv)	LEL (vol %)	Heat of Combustion (Btu/scf)
VOC**	VOC	16.05	16.05	11.42	1.2	4,415.00
Mixed Emissions:		16.05	16.05	11.42		

*** Assumes hexane as representative VOC*

STEP #3: Enter Potential Annual VOC Emissions

Potential VOC Annual Emission Rate: 70.31 TPY

STEP #4: Enter Operating Schedule and Utility Data

OPERATING SCHEDULE DATA:				
Hours per Shift		8	hrs/shift	
Shifts per Day		3	shifts/day	
Days per Year		365	days/year	
Operating Labor Hour		30	$/hr	(site specific)
Maintainence Labor Hour		35	$/hr	(site specific)
UTILITY DATA:				
Electricity Cost	$	0.065	$/kWh	(EIA)
Fuel Cost	$	7.46	$/mmBtu	(EIA)
WASTE DISPOSAL:				
Estimated Volume		1,000	gallons	
Estimated Cost	$	1.64	$/gallon	(assumed standard)

STEP #5: Enter Interest Rate, Equipment Life, and Inflation Rate Data

Interest Rate: 7%

Control Device	Equipment Life (Years)	Inflation Rate
Catatytic Incineration	15	
Life of Catalyst	5	
Thermal Regen. Incineration	15	
Thermal Recup. Incineration	15	
Carbon Adsorption[1]	15	
Life of Carbon[1]	5	10%
Biofiltration	15	
Life of Media	0.5	5%

Chemical Engineering Plant Index Cost Escalator: July 2008 Final
608.8

1- Used for Carbon Adsorption portion of Carbon Concentration Cost Analysis

STEP #1: Establish design specifications

Variable	Value
Preheater Inlet Waste Gas Volume Flow Rate, scfm	120,968
Preheater Inlet Waste Gas Temperature, F	150
VOC Content, lbs/hr	16.05
Relative Humidity, %	30
Desired Control Efficiency, including capture efficiency, %	95
Desired Percent Energy Recovery, %	90

Composition: Chemical Name	Actual VOC (lbs/hr)	Total VOC Weighted (lbs/hr)	Total Emissions (ppmv)	LEL (vol %)	Heat of Combustion (Btu/scf)
VOC	16.05	16.05	11.42	1.2	4,415
Mixed Emissions (ppmv):	16.05	16.05	11.42		

Annual VOC Emission 70.3136 TPY

*** Assumes hexane as representative VOC*

STEP #2: Verify that the oxygen content of the waste gas exceeds 20%

NOTE: It may be necessary to add auxiliary air if the oxygen content is less than 20%.

Variable	Value
Air Content, Volume %	100
Oxygen Content, %	20.9

STEP #3: Calculate the LEL and the percent of the LEL of the gas mixture

NOTE: If the mixture has an LEL above 25%, sufficient dilution air will be needed to bring the concentration of the mixture to less than 25% to satisfy fire insurance regulations.

Variable	Value
LEL, ppmv	12,000
LEL, %	0.1

STEP #4: Calculate the volumetric heat of combustion of the waste gas stream, Btu/scf

NOTE: Empirically, it has been found that 50 Btu/scf roughly corresponds to the LEL of organic/air mixtures. 25% LEL corresponds to 13 Btu/scf. For catalytic applications the heat of combustion must normally be less than 10 Btu/scf (for VOCs in air) to avoid excessively high temperatures in the catalyst bed. This is, of course, only an approximate guideline and may vary from system to system.

Variable	Value
Heat of Combustion, Btu/scf	0.05
Heat of Combustion per pound of incoming waste gas, Btu/lb	0.677

STEP #5c: Establish the desired outlet temperature of the catalyst bed

NOTE: *The energy released by the oxidation of the VOCs in the catalyst bed will raise the temperature of the gases by an amount as the gases pass throught the catalyst bed. An outlet temperature from the catalyst, and thus from the reactor, must be specified that will ensure the desired level of destruction of the VOC stream. Final design of the incinerator should be done by firms with experience in incinerator design. Guidelines indicate that values from 300 to 900 F result in destruction efficiencies between 90 and 95 percent. To prevent deactivation of the catalyst a maximum bed temperature of 1200 F should not be exceeded.*

Variable	Value
Outlet Temperature of the Catalyst Bed, °F	900

STEP #6c: Calculate the waste gas temp. at the exit of the preheater (primary) heat exchanger.

NOTE: *This temperature must not be close to the ignition temperature of the organic-containing gas to prevent damaging temperature excursions inside the heat exchanger should the gas ignite. Also, for gases containing halogens, sulfur, and phosphorous (or acid-forming atoms), this temperature must not drop below the acid dew.*

Variable	Value
Outlet Temperature of the Preheater, F	825

STEP #7c: Estimate the auxiliary fuel and power requirement and cost

ASSUMPTIONS:
(1) The reference temperature is taken as the inlet temp. of the auxiliary fuel (77 F).
(2) No auxiliary air is required.
(3) Energy losses are assumed to be 10% of the total energy input to the incinerator above ambient conditions.
(4) The heat capacities of the waste gases entering and leaving the combustion chamber are approximately the same regardless of composition.
(5) The mean heat capacities above the reference temperature of the waste gases entering and leaving the combustion chamber are approximately the same regardless of temperature.
(6) The fuel cost is estimated assuming a 1 hour start-up with no solvent load at the start of each day. The balance of the operating time requires either the with solvent load fuel requirement or (if the with solvent load requirement is negative) 5% of the fuel requirement without solvent load.

Variable		Value
Auxiliary Fuel Requirement (with solvent load), scfm		394.7
Auxiliary Fuel Requirement (without solvent load), scfm		402
Fuel Cost, $/MMBtu	$	7.46
Annual Fuel Cost, $	$	1,414,312
System Fan Pressure Drop, in. w.c.		20
Fan/Motor Efficiency, %		60
Power Requirement, kWh		4,146,451
Electricity Cost, $/kWh	$	0.065
Annual Electricity Cost, $	$	268,690

STEP #8c: Verify that the auxiliary fuel requirement is sufficient to stabilize the burner flame

NOTE: *Only a small amount of auxiliary fuel (< 5% of the total energy input) is needed to stablize the burner flame. If it is insufficient, than a minimum amount of auxiliary fuel must be used.*

Variable	Value
5% of Total Energy Input, Btu/min	91,532
Auxiliary Fuel Energy, Btu/min	352,404

STEP #9c: Estimate the inlet temperature to the catalyst bed

NOTE: *The inlet temperature to the catalyst bed must be calculated to ensure that the inlet temperature is above that necessary to ignite the combustible organic compounds in the catalyst selected for use. This temperature can be approximated using a "rule-of-thumb" which states that there will be a 25 F temperature rise for every 1% LEL.*

Variable	Value
Inlet Temperature to the Catalyst Bed, °F	898

STEP #10c: Calculate the total volumetric flow rate of gas through the incinerator

NOTE: *The total volumetric flow rate of gas leaving the incinerator is referred to as the flue gas flow rate and is the gas rate on which the incinerator sizing and cost correlations are based.*

Variable	Value
Total Volumetric Flow Rate, scfm	121,369

STEP #11c: Calculate the volume of catalyst in the catalyst bed

NOTE: *The proper space velocity to achieve a desired level of conversion is based on experimental data for the system involved. For precious metal catalysts, the space velocity generally lies between 10,000 1/hr and 60,000 1/hr. Final selection of the catalyst (and associated space velocity) should be done by firms with experience in incinerator design.*

Variable		Value
Space Velocity Required, 1/hr		30,000
Volume of Catalyst Required, ft^3		243
Catalyst Cost, $/ft^3	$	3,000
Expected Life of the Catalyst, years		5
Expected Interest Rate, %		7
Annual Catalyst Replacement Cost, $	$	177,606

QUOTATION USED: None

DIRECT COSTS:

Purchased Equipment Costs			
Incinerator		$	3,607,794
Auxiliary Equipment		$	-
Subtotal	A	$	3,607,794
Instrumentation	0.10 A	$	360,800
Sales taxes	0.03 A	$	108,200
Freight	0.05 A	$	180,400
Purchased equipment cost, PEC	B	$	4,257,194
Direct Installation Costs			
Foundation & supports	0.08 B	$	340,600
Handling & erection	0.14 B	$	596,000
Electrical	0.04 B	$	170,300
Piping	0.02 B	$	85,100
Insulation for ductwork	0.01 B	$	42,600
Painting	0.01 B	$	42,600
Direct installation cost	0.30 B	$	1,277,200
Site Preparation	SP	$	-
Buildings	Bldg.	$	-
TOTAL DIRECT COST	**DC**	**$**	**5,534,394**

INDIRECT COSTS (INSTALLATION)

Engineering	0.10 B	$	425,700
Construction and field expenses	0.05 B	$	212,900
Contractor fees	0.10 B	$	425,700
Start-up	0.02 B	$	85,100
Performance test	0.01 B	$	42,600
Contingencies	0.03 B	$	127,700
TOTAL INDIRECT COST	**IC**	**$**	**1,319,700**
TOTAL CAPITAL INVESTMENT (TCI)	**DC + IC**	**$**	**6,854,094**

QUOTATION USED: None

Hours per Shift (hrs)	8
Shifts per Day	3
Days per Year	365
Operating Labor Hour ($/hr)	30.00
Maintainence Labor Hour ($/hr)	35.00
VOC Emission Rate (tons/year)	70.31

Cost Item	Factor	Cost/Year

DIRECT ANNUAL COSTS (DC)

Operating labor				
Operator	0.5hr/shift x labor x shft/yr	$	16,400
Supervisor	0.15 x operator cost	$	2,500
Maintenance			
Labor	0.5hr/shift x labor x shft/yr	$	19,200
Material	same as labor	$	19,200
Catalyst replacement	See Step #11c	$	177,606
Utilities			
Fuel (Natural gas)	See Step #7c	$	1,414,312
Electricity	See Step #7c	$	268,690
TOTAL DC		**$**	**1,917,908**

INDIRECT ANNUAL COSTS (IC)

Overhead			0.60 x (operating labor + maint. costs)	$	34,400
Administrative	TCI	x	0.02	$	137,100
Property taxes	TCI	x	0.01	$	68,500
Insurance	TCI	x	0.01	$	68,500
Capital Recovery*	TCI	x	0.110	$	752,500
TOTAL IC				**$**	**1,061,000**

TOTAL ANNUALIZED COST	**DC + IC**	**$**	**2,978,908**
COST EFFECTIVENESS*	**($/ton of VOC removal)**	**$**	**44,596**

* Based on the following: Equipment Life = 15

Interest Rate = 7%

SUMMARY OF CONTROL DEVICE-SPECIFIC INPUT PARAMETERS

Desired Percent Energy Recovery, %	90
Outlet Temperature of the Catalyst Bed, °F	900
System Fan Pressure Drop, in. w.c.	20
Fan/Motor Efficiency, %	60
Space Velocity Required, 1/hr	30,000
Catalyst Cost, $/ft^3	3,000

*** Assumes Standard Industry Oxidizer Conditions ***

STEP #1: Establish design specifications

Variable	Value
Preheater Inlet Waste Gas Volume Flow Rate, scfm	120,968
Preheater Inlet Waste Gas Temperature, F	150
VOC Content, lbs/hr	16.05
Relative Humidity, %	30
Desired Control Efficiency, including capture efficiency, %	95
Desired Percent Energy Recovery, %	70

Composition: Chemical Name	Actual VOC (lbs/hr)	Total VOC Weighted (lbs/hr)	Total Emissions (ppmv)	LEL (vol %)	Heat of Combustion (Btu/scf)
VOC	16.05	16.05	11.42	1.2	4,415
Mixed Emissions (ppmv):	16.05	16.05	11.42		

Annual VOC Emission 70.3136 TPY

*** Assumes hexane as representative VOC*

STEP #2: Verify that the oxygen content of the waste gas exceeds 20%

NOTE: It may be necessary to add auxiliary air if the oxygen content is less than 20%.

Variable	Value
Air Content, Volume %	100
Oxygen Content, %	20.9

STEP #3: Calculate the LEL and the percent of the LEL of the gas mixture

NOTE: If the mixture has an LEL above 25%, sufficient dilution air will be needed to bring the concentration of the mixture to less than 25% to satisfy fire insurance regulations.

Variable	Value
LEL, ppmv	12,000
LEL, %	0.1

STEP #4: Calculate the volumetric heat of combustion of the waste gas stream, Btu/scf

NOTE: Empirically, it has been found that 50 Btu/scf roughly corresponds to the LEL of organic/air mixtures. 25% LEL corresponds to 13 Btu/scf. For catalytic applications the heat of combustion must normally be less than 10 Btu/scf (for VOCs in air) to avoid excessively high temperatures in the catalyst bed. This is, of course, only an approximate guideline and may vary from system to system.

Variable	Value
Heat of Combustion, Btu/scf	0.05
Heat of Combustion per pound of incoming waste gas, Btu/lb	0.677

STEP #5c: Establish the desired outlet temperature of the catalyst bed

NOTE: *The energy released by the oxidation of the VOCs in the catalyst bed will raise the temperature of the gases by an amount as the gases pass throught the catalyst bed. An outlet temperature from the catalyst, and thus from the reactor, must be specified that will ensure the desired level of destruction of the VOC stream. Final design of the incinerator should be done by firms with experience in incinerator design. Guidelines indicate that values from 300 to 900 F result in destruction efficiencies between 90 and 95 percent. To prevent deactivation of the catalyst a maximum bed temperature of 1200 °F should not be exceeded.*

Variable	Value
Outlet Temperature of the Catalyst Bed, °F	900

STEP #6c: Calculate the waste gas temp. at the exit of the preheater (primary) heat exchanger.

NOTE: *This temperature must not be close to the ignition temperature of the organic-containing gas to prevent damaging temperature excursions inside the heat exchanger should the gas ignite. Also, for gases containing halogens, sulfur, and phosphorous (or acid-forming atoms), this temperature must not drop below the acid dew.*

Variable	Value
Outlet Temperature of the Preheater, °F	675

STEP #7c: Estimate the auxiliary fuel and power requirement and cost

ASSUMPTIONS:
(1) The reference temperature is taken as the inlet temp. of the auxiliary fuel (77 °F).
(2) No auxiliary air is required.
(3) Energy losses are assumed to be 10% of the total energy input to the incinerator above ambient conditions.
(4) The heat capacities of the waste gases entering and leaving the combustion chamber are approximately the same regardless of composition.
(5) The mean heat capacities above the reference temperature of the waste gases entering and leaving the combustion chamber are approximately the same regardless of temperature.
(6) The fuel cost is estimated assuming a 1 hour start-up with no solvent load at the start of each day. The balance of the operating time requires either the with solvent load fuel requirement or (if the with solvent load requirement is negative) 5% of the fuel requirement without solvent load.

Variable	Value
Auxiliary Fuel Requirement (with solvent load), scfm	777.8
Auxiliary Fuel Requirement (without solvent load), scfm	785
Fuel Cost, $/MMBtu	$ 7.46
Annual Fuel Cost, $	$ 2,786,084
System Fan Pressure Drop, in. w.c.	20
Fan/Motor Efficiency, %	60
Power Requirement, kWh	4,159,569
Electricity Cost, $/kWh	$ 0.065
Annual Electricity Cost, $	$ 269,540

STEP #8c: Verify that the auxiliary fuel requirement is sufficient to stabilize the burner flame

NOTE: *Only a small amount of auxiliary fuel (< 5% of the total energy input) is needed to stablize the burner flame. If it is insufficient, than a minimum amount of auxiliary fuel must be used.*

Variable	Value
5% of Total Energy Input, Btu/min	91,821
Auxiliary Fuel Energy, Btu/min	688,491

STEP #9c: Estimate the inlet temperature to the catalyst bed

NOTE: *The inlet temperature to the catalyst bed must be calculated to ensure that the inlet temperature is above that necessary to ignite the combustible organic compounds in the catalyst selected for use. This temperature can be approximated using a "rule-of-thumb" which states that there will be a 25 F temperature rise for every 1% LEL.*

Variable	Value
Inlet Temperature to the Catalyst Bed, °F	898

STEP #10c: Calculate the total volumetric flow rate of gas through the incinerator

NOTE: *The total volumetric flow rate of gas leaving the incinerator is referred to as the flue gas flow rate and is the gas rate on which the incinerator sizing and cost correlations are based.*

Variable	Value
Total Volumetric Flow Rate, scfm	121,753

STEP #11c: Calculate the volume of catalyst in the catalyst bed

NOTE: *The proper space velocity to achieve a desired level of conversion is based on experimental data for the system involved. For precious metal catalysts, the space velocity generally lies between 10,000 1/hr and 60,000 1/hr. Final selection of the catalyst (and associated space velocity) should be done by firms with experience in incinerator design.*

Variable	Value
Space Velocity Required, 1/hr	30,000
Volume of Catalyst Required, ft^3	244
Catalyst Cost, $/ft^3	$ 3,000
Expected Life of the Catalyst, years	5
Expected Interest Rate, %	7
Annual Catalyst Replacement Cost, $	$ 178,169

QUOTATION USED: NONE

DIRECT COSTS:

Purchased Equipment Costs			
Incinerator** (escalated: July 2008 Final 608.8)			$ 1,652,996
Auxiliary Equipment			$ -
Subtotal		A	$ 1,652,996
Instrumentation		0.10 A	$ 165,300
Sales taxes		0.03 A	$ 49,600
Freight		0.05 A	$ 82,600
Purchased equipment cost, PEC		B	$ 1,950,496
Direct Installation Costs			
Foundation & supports		0.08 B	$ 156,000
Handling & erection		0.14 B	$ 273,100
Electrical		0.04 B	$ 78,000
Piping		0.02 B	$ 39,000
Insulation for ductwork		0.01 B	$ 19,500
Painting		0.01 B	$ 19,500
Direct installation cost		0.30 B	$ 585,100
Site Preparation		SP	$ -
Buildings		Bldg.	$ -
TOTAL DIRECT COST		**DC**	**$ 2,535,596**

INDIRECT COSTS (INSTALLATION)

Engineering	0.10 B	$ 195,000
Construction and field expenses	0.05 B	$ 97,500
Contractor fees	0.10 B	$ 195,000
Start-up	0.02 B	$ 39,000
Performance test	0.01 B	$ 19,500
Contingencies	0.03 B	$ 58,500
TOTAL INDIRECT COST	**IC**	**$ 604,500**
TOTAL CAPITAL INVESTMENT (TCI)	**DC + IC**	**$ 3,140,096**

**Base equipment cost = 1443 x Q0.5527; escalation indexes from Chemical Engineering.

QUOTATION USED: NONE

Hours per Shift (hrs)	8
Shifts per Day	3
Days per Year	365
Operating Labor Hour ($/hr)	30.00
Maintainence Labor Hour ($/hr)	35.00
VOC Emission Rate (tons/year)	70.31

Cost Item			Factor	Cost/Year
DIRECT ANNUAL COSTS (DC)				
Operating labor				
Operator			0.5hr/shift x labor x shft/yr	$ 16,400
Supervisor			0.15 x operator cost	$ 2,500
Maintenance				
Labor			0.5hr/shift x labor x shft/yr	$ 19,200
Material			same as labor	$ 19,200
Catalyst replacement			See Step #11c	$ 178,169
Utilities				
Fuel (Natural gas)			See Step #7c	$ 2,786,084
Electricity			See Step #7c	$ 269,540
TOTAL DC				**$ 3,291,093**
INDIRECT ANNUAL COSTS (IC)				
Overhead			0.60 x (operating labor + maint. costs)	$ 34,400
Administrative	TCI	x	0.02	$ 62,800
Property taxes	TCI	x	0.01	$ 31,400
Insurance	TCI	x	0.01	$ 31,400
Capital Recovery*	TCI	x	0.110	$ 344,800
TOTAL IC				**$ 504,800**
TOTAL ANNUALIZED COST			**DC + IC**	**$ 3,795,893**
COST EFFECTIVENESS*			**($/ton of VOC removal)**	**$ 56,827**

* Based on the following: Equipment Life = 15
Interest Rate = 7%

SUMMARY OF CONTROL DEVICE-SPECIFIC INPUT PARAMETERS

Desired Percent Energy Recovery, %	70
Outlet Temperature of the Catalyst Bed,°F	900
System Fan Pressure Drop, in. w.c.	20
Fan/Motor Efficiency, %	60
Space Velocity Required, 1/hr	30,000
Catalyst Cost, $/ft^3	3,000

***** Assumes Standard Industry Oxidizer Conditions *****

STEP #1: Establish design specifications

Variable	Value
Preheater Inlet Waste Gas Volume Flow Rate, scfm	120,968
Preheater Inlet Waste Gas Temperature, °F	150
Particulate Content, lbs/hr	16.05
Relative Humidity, %	30
Desired Control Efficiency, %	95
Desired Percent Energy Recovery, %	90

Composition:

Chemical Name	Total Emissions (ppmv)	LEL (vol %)	Heat of Combustion (Btu/scf)
VOC	11.42	1.2	4,415
Mixed Emissions (ppmv):	11.42		

Annual VOC Emission 70.3136 TPY

** Assumes hexane as representative VOC

STEP #2: Verify that the oxygen content of the waste gas exceeds 20%

NOTE: It may be necessary to add auxiliary air if the oxygen content is less than 20%.

Variable	Value
Air Content, Volume %	100
Oxygen Content, %	20.9

STEP #3: Calculate the LEL and the percent of the LEL of the gas mixture

NOTE: If the mixture has an LEL above 25%, sufficient dilution air will be needed to bring the concentration of the mixture to less than 25% to satisfy fire insurance regulations.

Variable	Value
LEL, ppmv	12,000
LEL, %	0.1

STEP #4: Calculate the volumetric heat of combustion of the waste gas stream, Btu/scf

NOTE: Empirically, it has been found that 50 Btu/scf roughly corresponds to the LEL of organic/air mixtures. 25% LEL corresponds to 13 Btu/scf. For catalytic applications the heat of combustion must normally be less than 10 Btu/scf (for VOCs in air) to avoid excessively high temperatures in the catalyst bed. This is, of course, only an approximate guideline and may vary from system to system.

Variable	Value
Heat of Combustion, Btu/scf	0.05
Heat of Combustion per pound of incoming waste gas, Btu/lb	0.677

STEP #5t: Establish the temperature at which the incinerator will operate.

NOTE: *In general, state and local regulations specify the required level of destruction that the customer must meet. For a given destruction requirement, there is a corresponding temperature at which the incinerator must operate. Guidelines indicate that temperatures in the range of 1200 to 1600 F result in destruction efficiencies in the range of 95 to 98 percent. Many incinerators can achieve destruction efficiencies of 99 percent or higher. Final design of the incinerator should be done by firms with experience in incinerator design.*

Variable	Value
Incinerator Operating Temperature, °F	1,400

STEP #6t: Calculate the waste gas temp. at the exit of the preheater (primary) heat exchanger.

NOTE: *This temperature must not be close to the ignition temperature of the organic-containing gas to prevent damaging temperature excursions inside the heat exchanger should the gas ignite. Also, for gases containing halogens, sulfur, and phosphorous (or acid-forming atoms), this temperature must not drop below the acid dew.*

Variable	Value
Outlet Temperature of the Preheater, °F	1,275

STEP #7t: Estimate the auxiliary fuel and power requirement and cost

ASSUMPTIONS:
(1) The reference temperature is taken as the inlet temp. of the auxiliary fuel (77 °F).
(2) No auxiliary air is required.
(3) Energy losses are assumed to be 10% of the total energy input to the incinerator above ambient conditions.
(4) The heat capacities of the waste gases entering and leaving the combustion chamber are approximately the same regardless of composition.
(5) The mean heat capacities above the reference temperature of the waste gases entering and leaving the combustion chamber are approximately the same regardless of temperature.
(6) The fuel cost is estimated assuming a 1 hour start-up with no solvent load at the start of each day. The balance of the operating time requires either the with solvent load fuel requirement or (if the with solvent load requirement is negative) 5% of the fuel requirement without solvent load.

Variable		Value
Auxiliary Fuel Requirement (with solvent load), scfm		673
Auxiliary Fuel Requirement (without solvent load), scfm		680
Fuel Cost, $/MMBtu	$	7.46
Annual Fuel Cost, $	$	2,410,868
System Fan Pressure Drop, in. w.c.		20
Fan/Motor Efficiency, %		60
Power Requirement, kWh		4,155,982
Electricity Cost, $/kWh	$	0.065
Annual Electricity Cost, $	$	269,308

STEP #8t: Verify that the auxiliary fuel requirement is sufficient to stabilize the burner flame

NOTE: *Only a small amount of auxiliary fuel (< 5% of the total energy input) is needed to stablize the burner flame. If it is insufficient, than a minimum amount of auxiliary fuel must be used.*

Variable	Value
5% of Total Energy Input, Btu/min	147,479
Auxiliary Fuel Energy, Btu/min	596,815

STEP #9t: Calculate the total volumetric flow rate of gas through the incinerator

NOTE: *The total volumetric flow rate of gas leaving the incinerator is referred to as the flue gas flow rate and is the gas rate on which the incinerator sizing and cost correlations are based.*

Variable	Value
Total Volumetric Flow Rate, scfm	121,648

QUOTATION USED: NONE

DIRECT COSTS:

Purchased Equipment Costs			
Incinerator** (escalated: July 2008 Fin 608.8)		$	2,879,574
Auxiliary Equipment		$	-
Subtotal	A	$	2,879,574
Instrumentation	0.10 A	$	288,000
Sales taxes	0.03 A	$	86,400
Freight	0.05 A	$	144,000
Purchased equipment cost, PEC	B	$	3,397,974
Direct Installation Costs			
Foundation & supports	0.08 B	$	271,800
Handling & erection	0.14 B	$	475,700
Electrical	0.04 B	$	135,900
Piping	0.02 B	$	68,000
Insulation for ductwork	0.01 B	$	34,000
Painting	0.01 B	$	34,000
Direct installation cost	0.30 B	$	1,019,400
Site Preparation	SP	$	-
Buildings	Bldg.	$	-
TOTAL DIRECT COST	**DC**	**$**	**4,417,374**

INDIRECT COSTS (INSTALLATION)

Engineering	0.10 B	$	339,800
Construction and field expenses	0.05 B	$	169,900
Contractor fees	0.10 B	$	339,800
Start-up	0.02 B	$	68,000
Performance test	0.01 B	$	34,000
Contingencies	0.03 B	$	101,900
TOTAL INDIRECT COST	**IC**	**$**	**1,053,400**
TOTAL CAPITAL INVESTMENT (TCI)	**DC + IC**	**$**	**5,470,774**

**Base equipment cost = $2.204 \times 10^5 + 11.57 \times Q$; escalation indexes from *Chemical Engineering* .

QUOTATION USED: NONE

Hours per Shift (hrs)	8
Shifts per Day	3
Days per Year	365
Operating Labor Hour ($/hr)	30.00
Maintainence Labor Hour ($/hr)	35.00
VOC Emission Rate (tons/year)	70.31

Cost Item			Factor		Cost/Year
DIRECT ANNUAL COSTS (DC)					
Operating labor					
Operator			0.5hr/shift x labor x shft/yr	$	16,400
Supervisor			0.15 x operator cost	$	2,500
Maintenance					
Labor			0.5hr/shift x labor x shft/yr	$	19,200
Material			same as labor	$	19,200
Utilities					
Fuel (Natural gas)			See Step #7t, Page 3	$	2,410,868
Electricity			See Step #7t, Page 3	$	269,308
TOTAL DC				**$**	**2,737,476**
INDIRECT ANNUAL COSTS (IC)					
Overhead			0.60 x (operating labor + maint. costs)	$	34,400
Administrative	TCI	x	0.02	$	109,400
Property taxes	TCI	x	0.01	$	54,700
Insurance	TCI	x	0.01	$	54,700
Capital Recovery*	TCI	x	0.110	$	600,700
TOTAL IC				**$**	**853,900**
TOTAL ANNUALIZED COST			**DC + IC**	**$**	**3,591,376**
COST EFFECTIVENESS*			**($/ton of VOC removal)**	**$**	**53,765**

* Based on the following: Equipment Life = 15
Interest Rate = 7%

SUMMARY OF CONTROL DEVICE-SPECIFIC INPUT PARAMETERS

Desired Percent Energy Recovery, %	90
Incinerator Operating Temperature, °F	1,400
System Fan Pressure Drop, in. w.c.	20
Fan/Motor Efficiency, %	60

*** Assumes Standard Industry Oxidizer Conditions ***

STEP #1: Establish design specifications

Variable	Value
Preheater Inlet Waste Gas Volume Flow Rate, scfm	120,968
Preheater Inlet Waste Gas Temperature, F	150
Particulate Content, lbs/hr	16.05
Relative Humidity, %	30
Desired Control Efficiency, %	95
Desired Percent Energy Recovery, %	70

Composition:

Chemical Name	Total Emissions (ppmv)	LEL (vol %)	Heat of Combustion (Btu/scf)
VOC	11.42	1.2	4,415
Mixed Emissions (ppmv):	11.42		

Annual VOC Emission 70.3136 TPY

** Assumes hexane as representative VOC

STEP #2: Verify that the oxygen content of the waste gas exceeds 20%

NOTE: It may be necessary to add auxiliary air if the oxygen content is less than 20%.

Variable	Value
Air Content, Volume %	100
Oxygen Content, %	20.9

STEP #3: Calculate the LEL and the percent of the LEL of the gas mixture

NOTE: If the mixture has an LEL above 25%, sufficient dilution air will be needed to bring the concentration of the mixture to less than 25% to satisfy fire insurance regulations.

Variable	Value
LEL, ppmv	12,000
LEL, %	0.1

STEP #4: Calculate the volumetric heat of combustion of the waste gas stream, Btu/scf

NOTE: Empirically, it has been found that 50 Btu/scf roughly corresponds to the LEL of organic/air mixtures. 25% LEL corresponds to 13 Btu/scf. For catalytic applications the heat of combustion must normally be less than 10 Btu/scf (for VOCs in air) to avoid excessively high temperatures in the catalyst bed. This is, of course, only an approximate guideline and may vary from system to system.

Variable	Value
Heat of Combustion, Btu/scf	0.05
Heat of Combustion per pound of incoming waste gas, Btu/lb	0.677

STEP #5t: Establish the temperature at which the incinerator will operate.

NOTE: *In general, state and local regulations specify the required level of destruction that the customer must meet. For a given destruction requirement, there is a corresponding temperature at which the incinerator must operate. Guidelines indicate that temperatures in the range of 1200 to 1600 F result in destruction efficiencies in the range of 95 to 98 percent. Many incinerators can achieve destruction efficiencies of 99 percent or higher. Final design of the incinerator should be done by firms with experience in incinerator design.*

Variable	Value
Incinerator Operating Temperature, °F	1,400

STEP #6t: Calculate the waste gas temp. at the exit of the preheater (primary) heat exchanger.

NOTE: *This temperature must not be close to the ignition temperature of the organic-containing gas to prevent damaging temperature excursions inside the heat exchanger should the gas ignite. Also, for gases containing halogens, sulfur, and phosphorous (or acid-forming atoms), this temperature must not drop below the acid dew.*

Variable	Value
Outlet Temperature of the Preheater, °F	1,025

STEP #7t: Estimate the auxiliary fuel and power requirement and cost

ASSUMPTIONS:

(1) The reference temperature is taken as the inlet temp. of the auxiliary fuel (77 °F).
(2) No auxiliary air is required.
(3) Energy losses are assumed to be 10% of the total energy input to the incinerator above ambient conditions.
(4) The heat capacities of the waste gases entering and leaving the combustion chamber are approximately the same regardless of composition.
(5) The mean heat capacities above the reference temperature of the waste gases entering and leaving the combustion chamber are approximately the same regardless of temperature.
(6) The fuel cost is estimated assuming a 1 hour start-up with no solvent load at the start of each day. The balance of the operating time requires either the with solvent load fuel requirement or (if the with solvent load requirement is negative) 5% of the fuel requirement without solvent load.

Variable		Value
Auxiliary Fuel Requirement (with solvent load), scfm		1334.3
Auxiliary Fuel Requirement (without solvent load), scfm		1,341.3
Fuel Cost, $/MMBtu	$	7.46
Annual Fuel Cost, $	$	4,778,753
System Fan Pressure Drop, in. w.c.		20
Fan/Motor Efficiency, %		60
Power Requirement, kWh		4,178,565
Electricity Cost, $/kWh	$	0.065
Annual Electricity Cost, $	$	270,771

STEP #8t: Verify that the auxiliary fuel requirement is sufficient to stabilize the burner flame

NOTE: *Only a small amount of auxiliary fuel (< 5% of the total energy input) is needed to stablize the burner flame. If it is insufficient, than a minimum amount of auxiliary fuel must be used.*

Variable	Value
5% of Total Energy Input, Btu/min	148,281
Auxiliary Fuel Energy, Btu/min	1,176,698

STEP #9t: Calculate the total volumetric flow rate of gas through the incinerator

NOTE: *The total volumetric flow rate of gas leaving the incinerator is referred to as the flue gas flow rate and is the gas rate on which the incinerator sizing and cost correlations are based.*

Variable	Value
Total Volumetric Flow Rate, scfm	122,309

QUOTATION USED: NONE

DIRECT COSTS:

Purchased Equipment Costs				
Incinerator** (Escalated July 2008 Fina	608.8)		$	707,484
Auxiliary Equipment			$	-
Subtotal		A	$	707,484
Instrumentation		0.10 A	$	70,700
Sales taxes		0.03 A	$	21,200
Freight		0.05 A	$	35,400
Purchased equipment cost, PEC		B	$	834,784
Direct Installation Costs				
Foundation & supports		0.08 B	$	66,800
Handling & erection		0.14 B	$	116,900
Electrical		0.04 B	$	33,400
Piping		0.02 B	$	16,700
Insulation for ductwork		0.01 B	$	8,300
Painting		0.01 B	$	8,300
Direct installation cost		0.30 B	$	250,400
Site Preparation		SP	$	-
Buildings		Bldg.	$	-
TOTAL DIRECT COST		**DC**	**$**	**1,085,184**

INDIRECT COSTS (INSTALLATION)

Engineering	0.10 B	$	83,500
Construction and field expenses	0.05 B	$	41,700
Contractor fees	0.10 B	$	83,500
Start-up	0.02 B	$	16,700
Performance test	0.01 B	$	8,300
Contingencies	0.03 B	$	25,000
TOTAL INDIRECT COST	**IC**	**$**	**258,700**
TOTAL CAPITAL INVESTMENT (TCI)	**DC + IC**	**$**	**1,343,884**

**Base equipment cost = 21342 x $Q^{0.2500}$; escalation indexes from *Chemical Engineering* .

QUOTATION USED: NONE

Hours per Shift (hrs)	8
Shifts per Day	3
Days per Year	365
Operating Labor Hour ($/hr)	30.00
Maintainence Labor Hour ($/hr)	35.00
VOC Emission Rate (tons/year)	70.31

Cost Item	Factor		Cost/Year
DIRECT ANNUAL COSTS (DC)			
Operating labor			
Operator	0.5hr/shift x labor x shft/yr	$	16,400
Supervisor	0.15 x operator cost	$	2,500
Maintenance			
Labor	0.5hr/shift x labor x shft/yr	$	19,200
Material	same as labor	$	19,200
Utilities			
Fuel (Natural gas)	See Step #7t, Page 3	$	4,778,753
Electricity	See Step #7t, Page 3	$	270,771
TOTAL DC		**$**	**5,106,824**

INDIRECT ANNUAL COSTS (IC)

Overhead			0.60 x (operating labor + maint. costs)	$	34,400
Administrative	TCI	x	0.02	$	26,900
Property taxes	TCI	x	0.01	$	13,400
Insurance	TCI	x	0.01	$	13,400
Capital Recovery*	TCI	x	0.110	$	147,600
TOTAL IC				**$**	**235,700**

TOTAL ANNUALIZED COST	**DC + IC**	**$**	**5,342,524**
COST EFFECTIVENESS*	**($/ton of VOC removal)**	**$**	**79,980**

* Based on the following: Equipment Life = 15
Interest Rate = 7%

SUMMARY OF CONTROL DEVICE-SPECIFIC INPUT PARAMETERS	
Desired Percent Energy Recovery, %	70
Incinerator Operating Temperature, °F	1,400
System Fan Pressure Drop, in. w.c.	20
Fan/Motor Efficiency, %	60

** *Assumes Standard Industry Oxidizer Conditions* **

STEP #1: Establish design specifications

Variable	Value
Inlet Waste Gas Volume Flow Rate, scfm	120,968
Inlet Waste Gas Temp., °F (if above 130 °F, pretreatment may be required)	150
VOC Content, lbs/hr	16.05
Relative Humidity, % (if above 50%, dehumidification may be required)	30
Desired Control Efficiency, %	95

Composition:

Chemical Name	Total Emissions (ppmv)	LEL (vol %)	Molecular Weight
VOC	11.42	1.2	86.20
Mixed Emissions (ppmv):	11.42		
Partial Pressure (psia):	0.0002		

NOTE: Hexane assumed to represent volatile components present in the Die Lube

STEP #2: Verify that the oxygen content of the waste gas exceeds 20%

NOTE: It may be necessary to add auxillary air if the oxygen content is less than 20%.

Variable	Value
Air Content, Volume %	100
Oxygen Content, %	20.9

STEP #3: Calculate the LEL and the percent of the LEL of the gas mixture

NOTE: If the mixture has an LEL above 25%, sufficient dilution air will be needed to bring the concentration of the mixture to less than 25% to satisfy fire insurance regulations.

Variable	Value
LEL, ppmv	12,000
LEL, %	0.1

STEP #4: Calculate the biofilter volume and estimate the capital cost

VOC

Variable		Value
Total Emissions, lb/hr		16.05333333
Published Elimination Rate, lb/ft^3-hr	Default to Total VOC	0.00568
Volume Required, ft^3		2,685
Volume Require, yd^3		99

Face Velocity:

Variable	Value
Design Face Velocity, scfm/ft^2 (16 scfm/ft^2 recommended, reference 2)	16
Required Surface Area, ft^2	8,588
Volume Required, ft^3 (based on 3 foot bed depth)	25,765
Volume Required, yd^3	954

Required Volume, yd^3 954

Capital Cost[1] 3,180,837

[1]Assume $500,000 per 150 cubic yards based on "Full-Scale Biofilter Demonstration Project for the Control of Ethanol Emissions from an Investment Foundry." RMT, Inc., September 1993.

[2]Based on "Application of Biofiltration to the Control of Air Toxics and Other VOC Emissions," Leson, Gero, RMT, Inc. Presented at the 84th Annual Air & Waste Management Meeting, June 16, 1991.

STEP #5: Estimate media replacement costs

Variable		Value
Media Required, cyd		954
Media Price, $/cyd	$	50
Expected Life of the Media, years		0.5
Expected Inflation Rate, %		5
Freight and Sales Tax Factor		1.08
Media Cost, $/replacement	$	47,713
Annual Media Replacement Cost, $	$	106,910
Replacement Labor, $/cyd (2 person crew @ 1 day per replacement @ $50/hr/person)	$	2.40
Annual Media Replacement Labor, $	$	4,750

STEP #6: Calculate the direct annual cost for utilities

NOTE: *The following operation schedule and electricity cost has been assumed:*

Hours per Shift (hrs)		*8*
Shifts per Day		*3*
Days per Year		*365*
Electricity Price, $/kWh	*$*	*0.065*

An overall fan(pump)/motor efficiency of 60% has been assumed.

ENERGY:

Variable	Value
System Fan Pressure Drop, in. w.c.	15
Fan/Motor Efficiency, %	60
Power Requirement, kWh	3,099,556
Electricity Cost, $/kWh	0.065
Annual Electricity Cost, $	200,851

ALTERNATE ENERGY ESTIMATE *Total energy requirement is 0.0027 kWhr/scfm/hr (see reference 1, step #4)*
All system energy supplied by electricity

Cost of Electricity, $	$	0.065
Operational Cost, $/scfm/hr	$	0.0002
Annual Energy Cost, $	$	185,401
Use	$	185,401

WATER AND SEWER:

ASSUMPTIONS: *Estimate $0.15 per scfm of air flow per year (see reference 1, step #4)*

Annual Sewer and Water Cost, $	$	18,145

QUOTATION USED: None

DIRECT COSTS:

Purchased Equipment Costs				
Vessel(s) and media (Escalated to: July 2008 Final	608.8)		$	5,653,995
Auxiliary equipment (Inlet Preconditioner, estimate)			$	-
Subtotal	A		$	5,653,995
Instrumentation	0.10 A		$	565,400
Sales taxes	0.03 A		$	169,600
Freight	0.05 A		$	282,700
Purchased equipment cost, PEC	B		$	6,671,695
Direct Installation Costs				
Foundation & supports	0.08 B		$	533,700
Handling & erection	0.14 B		$	934,000
Electrical	0.04 B		$	266,900
Piping	0.02 B		$	133,400
Insulation for ductwork	0.01 B		$	66,700
Painting	0.01 B		$	66,700
Direct installation cost	0.30 B		$	2,001,400
Site Preparation	SP		$	-
Buildings	Bldg.		$	100,000
TOTAL DIRECT COST	**DC**		**$**	**8,773,095**

INDIRECT COSTS (INSTALLATION):

Engineering	0.10 B	$	667,200
Construction and field expenses	0.05 B	$	333,600
Contractor fees	0.10 B	$	667,200
Start-up	0.02 B	$	133,400
Performance test	0.01 B	$	66,700
Contingencies	0.03 B	$	200,200
TOTAL INDIRECT COST	**IC**	**$**	**2,068,300**
TOTAL CAPITAL INVESTMENT (TCI)	**DC + IC**	**$**	**10,841,395**

†Base equipment cost per Step #4, Page 2; escalation indexes from Chemical Engineering.

QUOTATION USED: None

Hours per Shift (hrs)	8
Shifts per Day	3
Days per Year	365
Operating Labor Hour ($/hr)	30
Maintainence Labor Hour ($/hr)	35
VOC Emission Rate (tons/year)	70.31

Cost Item			Factor		Cost/Year
DIRECT ANNUAL COST (DC)					
Operating Labor					
Operator			0.5hr/shift x labor x shft/yr	$	16,400
Supervisor			0.15 x operator cost	$	2,500
Maintenance					
Labor			0.5hr/shift x labor x shft/yr	$	19,200
Material			same as labor	$	19,200
Bed Replacement					
Labor				$	4,750
Material				$	106,910
Utilities					
Water				$	18,145
Electricity				$	185,401
TOTAL DC				**$**	**372,506**
INDIRECT ANNUAL COST (IC)					
Overhead			0.60 x (operating labor + maint. costs)	$	34,400
Administrative	TCI	x	0.02	$	216,800
Property taxes	TCI	x	0.01	$	108,400
Insurance	TCI	x	0.01	$	108,400
Capital Recovery*	TCI	x	0.110	$	1,190,300
TOTAL IC				**$**	**1,658,300**
RECOVERY CREDIT (RC)				**$**	**-**
TOTAL ANNUALIZED COST			**DC + IC - RC**	**$**	**2,030,806**
COST EFFECTIVENESS			**($/ton of VOC removal)**	**$**	**30,402**

* Based on the following: Equipment Life = 15
Interest Rate = 7%

CONTROL DEVICE-SPECIFIC INPUT PARAMETERS	Cost Analysis Page 29 of 29 Appx C	
Published Elimination Rate, lb/ft^3-hr		0.00568
Design Face Velocity, scfm/ft^2 (16 scfm/ft^2 recommended, reference 2)		16
Media Price, $/cyd	$	50.00
Freight and Sales Tax Factor		1.08
Replacement Labor, $/cyd (2 person crew @ 1 day per replacement @ $50/hr/person)	$	2.40
System Fan Pressure Drop, in. w.c.		15
Fan/Motor Efficiency, %		60

***** Refer to Quotation Section for Quote-Specific Inputs, As Necessary *****

BOTTOM OF SPREADSHEET

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Don Fork
Jet Corr, Inc.
3155 SR 49
Valparaiso, IN 46393

DATE: March 27, 2014

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

SUBJECT: Final Decision
Part 70 Operating Permit
127-33924-00094

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:
David Wiser, Responsible Official
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

March 27, 2014

TO: Porter County Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Jet Corr, Inc.
Permit Number: 127-33924-00094

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	PWAY 3/26/2014 Jet Corr, Inc. 127-33924-00094 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Don Fork Jet Corr, Inc. 3155 SR 49 Valparaiso IN 46393 (Source CAATS)									
2		David Wiser CFO Jet Corr, Inc. 1800 C Sarasota Business Pkwy Conyers GA 30252 *(RO CAATS)*									
3		Porter County Public Library 103 Jefferson St Valparaiso IN 46383 *(Library)*									
4		Porter County Board of Commissioners 155 Indiana Ave, Ste 205 Valparaiso IN 46383 *(Local Official)*									
5		Porter County Health Department 155 Indiana Ave, Suite 104 Valparaiso IN 46383-5502 *(Health Department)*									
6		Shawn Sobocinski 3229 E. Atlanta Court Portage IN 46368 *(Affected Party)*									
7		Mr. Ed Dybel 2440 Schrage Avenue Whiting IN 46394 *(Affected Party)*									
8		Valparaiso City Council and Mayors Office 166 Lincolnway Valparaiso IN 46383-5524 *(Local Official)*									
9		Mr. Joseph Virgil 128 Kinsale Avenue Valparaiso IN 46385 *(Affected Party)*									
10		Mark Coleman 107 Diana Road Portage IN 46368 *(Affected Party)*									
11		Mr. Chris Hernandez Pipefitters Association, Local Union 597 8762 Louisiana St., Suite G Merrillville IN 46410 *(Affected Party)*									
12		Burns Harbor Town Council 1240 N. Boo Rd Burns Harbor IN 46304 *(Local Official)*									
13		Eric & Sharon Haussman 57 Shore Drive Ogden Dunes IN 46368 (Affected Party)									
14		Joseph Hero 11723 S Oakridge Drive St. John IN 46373 *(Affected Party)*									
15		Matt Mikus 1710 Vale Park Rd Apt 302 Valparaiso IN 46383 *(Affected Party)*									

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